UNIVERSIDAD PONTIFICIA COMILLAS

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

OFFICIAL MASTER'S DEGREE IN THE ELECTRIC POWER INDUSTRY

Master's Thesis

ASSESSMENT OF ALTERNATIVE DESIGNS OF CAPACITY REMUNERATION MECHANISMS IN THE SPANISH POWER SYSTEM IN THE 2030 HORIZON

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Madrid, July 2016

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Executive Summary

Capacity margins in the Spanish electricity system are currently in safe levels. However, this situation may no longer hold in the medium- to long-term, as there is considerable uncertainty about the evolution of the generation fleet and the demand, namely:

- Nuclear power plants will reach the end of their 40-year design life in the 2020s. Nevertheless, there exists the possibility of a life extension beyond 40 years
- A rise in carbon prices would jeopardize the economic viability of coal power plants leading to their shut-down. Additionally, public support to domestic coal power plants may no longer be in force in the future.
- Moving towards a low carbon mix would require higher levels of back-up thermal generation, namely CCGT.

In this vein, three alternative scenarios have been formulated so as to represent plausible evolutions of the energy mix in the period 2020-2030. Under these hypothesis, the new capacity that would be required so as to assure a secure electricity supply during that period might vary between 13.56 GW and 20.78 GW.

However, in the current context of low and volatile market prices and low load factors is not sending the right economic signals for attracting investors. In the discussion about whether or not the energy-only is able to guarantee SoS in the Spanish electricity system, we conclude that there is a market failure that should be addressed through the implementation of a CRM. This mechanism must be able to send a stable long term signal to investors so as to allow them to recover their fixed costs.

An analysis of the state of the art of the different alternative design of CRM has been carried out, with a focus on the particular problem that characterizes the Spanish power system. Guidelines and good practices coming from the Spanish regulator and European institutions have been also studied.

As a result of the assessment, it has been concluded that the most suited CRM alternatives for bringing into the system the new capacity that Spain requires are a capacity market based on a central auction and a reliability option mechanism. These alternatives are considered to be cost-efficient due to its competitive nature and flexible to adapt to the actual and long-term needs of the system.

These alternatives have been introduced in an electricity wholesale market model for long-term analysis. It has been simulated the entrance of new capacity into the system in the amount required so as to take the coverage index into save levels under the hypothesis of the three scenarios. For fostering these investments the existence of two alternative CRM have been simulated, namely: a central buyer model (CM) and a reliability option mechanism (RO).

The design basic criteria of these CRM has been to set the level of remuneration so as to be effective and efficient form the point of view of the regulator, in way that:

1. The remuneration level allows plants to recover all their fixed cost, including a reasonable profitability.
2. The cost charged onto consumers will be the lowest possible

The results obtained from this study for the year 2030 are shown in the following table:

Table. Main results obtained from the simulations of the CRMs in the three scenarios for the year 2030.

			Low scenario	***Medium scenario***	***High scenario***
	New net CCGT capacity	[GW]	13.56	20.36	20.78
CM	Weighed energy price	[€/MWh]	84.2	86.7	85.7
	Cost of the mechanism	[€/MWh]	5.2	6.2	6.7
	Total costs for consumers	[€/MWh]	89.5	92.9	92.4
	Premium	[€/kW]	122.5	112.1	115.4
RO	Weighed energy price	[€/MWh]	82.8	84.5	83.7
	Cost of the mechanism	[€/MWh]	5.7	7.2	7.6
	Total costs for consumers	[€/MWh]	88.5	91.8	91.3
	Premium	[€/kW]	120.9	113.7	116.9

Under the hypothesis assumed, the total energy costs (understood as the sum of the spot energy price and the cost of the CRM), results lower when implementing a CRM than in an energy-only-market approach.

On the other hand, the costs of the CRM per unit of energy obtained from the simulations are comparable with those registered in Spain with the current mechanisms.

Additionally, it can be demonstrated that the existence of a certain amount of capacity subject to a RO contract leads to a reduction in market energy price., due the stabilizing effect of the 'scarcity price'. Variations in the level of investment incentives are linked to the load factor of the plants, the spot price and their variable cost.

Table of Contents

CHAPTER I: **Introduction**

I.1. MOTIVATION

There are several aspects that justify the development of a master thesis focused on a Alternative for the implementation of Capacity Remuneration Mechanisms (hereinafter, **CRM)** in the Spanish power system, namely:

- Capacity margins in the Spanish electricity system are currently in safe levels. However, this situation may no longer hold in the medium- to long-term, as there is considerable uncertainty about the evolution of the generation fleet and the demand, namely:
    - Nuclear power plants will reach the end of their 40-year design life in the 2020s. On the one hand, there exists the possibility of a life extension beyond 40 years. On the other hand, current trends in other countries as well as the view of some political parties may lead to a nuclear phase-out.
    - A rise in carbon prices and increased environmental requirements would jeopardize the economic viability of coal power plants leading to their shut-down. Additionally, domestic coal power plants have been reliant on public support justified by security of supply (hereinafter, **SoS**) reasons, which may no longer be in force in the future.
    - A switch to a more renewable generation mix would require higher levels of back-up thermal generation, namely CCGT. However, a combined scenario of low market prices and low load factors would not be attractive for investors.
- In this vein, the Spanish Regulator CNE expressed its concerns about the medium and long-term SoS of the Spanish power system and launched a public consultation on the design of a new CRM back in December 2012 (CNE, 2012b). Specifically, the CNE justified the necessity of a CRM on this basis:
    - The existence of a price cap does not allow scarcity prices to be reflected.
    - Low levels of demand elasticity to market prices.
    - Risk of deficit of reserve margin in the long-term due to lack of investment.
    - Low interconnection capacity with Europe.
    - High penetration of Renewable Energy Sources (hereinafter, RES) that feature low levels of firmness and require back-up conventional generation
- Nevertheless, no further progress has been made in the development of the new CRM in Spain ever since.
- In parallel, at European level, the European Commission (hereinafter, **EC**) launched in April 2015 an inquiry about CRM and a draft of the results has been recently published. The main purpose of this inquiry is to establish whether the different envisaged or already implemented CRM are likely to succeed in ensuring capacity adequacy and firmness without distorting competition or trade in the Internal Electricity Market (hereinafter, **IEM**).
- As per the design and performance of the current Spanish CRM, the outcome of the assessment was negative. According to the EC's analysis, the Spanish CRM has led to an inefficient outcome as a consequence of a flawed design
- As a matter of fact, the Spanish approach for CRM is complex and has included:
    i. Capacity payments in which the payment was administratively determined subject to successive modifications in terms of the level of the payment and the duration;
    ii. Availability payments introduced in a context of overcapacity against the criterion of the CNE;

iii. A controversial demand response payment targeted to big consumers which has seldom been used thus putting a significant burden to system regulated cost;
iv. A "security of supply" capacity payment for domestic coal units.

- All of the above calls for a systematic approach in the design of a Alternative for a new CRM to be incorporated to the Spanish regulation that:
  - Can attract the required amount of investment in the relevant timeframe.
  - Is compliant with the regulatory and economic principles in the design of CRM.
  - Follows the recommendations of the Spanish Regulator and EC guidelines.
  - In sum, is efficient in terms of the cost for the system with regard to the utility provided.

I.2. OBJECTIVES

The specific objectives of this master thesis are as follows:

- The review of the relevant literature, whether academic or published by regulatory bodies, on the different existing CRM designs. This will provide the required insight in order to understand the pros and cons of each approach and the key design parameters to be considered so as to achieve a suitable design in the specific context of the Spanish Power System in the 2020-2030.
- The definition of a set of plausible future scenarios of evolution of the Spanish Power System beyond 2020 under different assumptions of selective technological phase-out, evolution of demand, RES penetration, carbon prices, etc.
- The definition of potential CRM designs (e.g. capacity payments, reliability options, etc.) within the Spanish electricity sector in order to guarantee medium and long-term SoS and the quantification of the relevant parameters, including strike prices, premiums, duration of the mechanism, eligibility in terms of new vs existing capacity, technological target vs market-wide, etc.
- The integration of the assessment of CRM into the Iberian wholesale electricity market model developed by the KPMG Economics & Regulation Practice.
- The assessment of the CRM proposed under the different scenarios in terms of system regulated costs, market prices, level of adequacy, efficiency and cost recovery of generating plants, etc. All of this with the ultimate objective of proposing recommendations on alternative designs vis-à-vis the implementation of a CRM in the Spanish Power System in the 2020-2030 horizon.

I.3. CHALLENGES

- Definition of plausible scenarios of evolution of the Spanish power system:
    - The achievement of a sufficient insight of the current Spanish generation mix
    - The understanding of market dynamics
    - The analysis of national and international trends in power markets
    - All of this with the objective of defining a set of potential alternative scenarios for the Spanish power system
- Design of alternatives of CRM for the Spanish power system:
    - Gaining a deep knowledge of the pros and cons of the different alternative designs and notably their impact on market dynamics.
    - Design a robust mechanism, which achieves a trade-off between generality (for extrapolating results and be able to adapt it to uncertain events), and specificity, for representing the particular Spanish case.
- Become familiar with power market models.

I.4. DESCRIPTION OF THE METHODOLOGY

The starting point of this study is the **identification of the key issues of the CRM**. For this purpose, a research will be conducted with a focus on the following sources of information:

- State-of-the-art academic literature.
- EC guidelines on the subject which are currently being discussed in the context of the full implementation of the IEM.
- Reports elaborated by the Spanish Regulator (CNE/CNMC) in the context of the consultation process on the design of CRM for the Spanish Power System.

The following step will be the **design of alternatives of CRM**. The aim is to present a menu of alternatives that can guarantee the adequacy of the Spanish electricity system in the long-term and that are compatible with the European guidelines and recommendation and the specific Spanish power system requirements.

Once the alternatives are defined, **different scenarios** will be developed so as to test the behaviour and performance of the proposed CRM designs. These scenarios will depict alternative future outcomes of the Spanish power system in the 2020-2030 horizon. The scenarios will be designed on the basis of planning reports elaborated by the Spanish Authorities (e.g. Ministry of Industry, REE, CNMC) as well as any other relevant authorized source on the matter.

The next step is the **study and adaptation of an in-house model of the Spanish Wholesale Market** developed by the KPMG Economics & Regulation Practice. Firstly, the model should be adapted in order to represent precisely the main specificities of the variables that are going to be analysed. Secondly, **the alternatives and scenarios will be introduced and simulated** for obtaining solid output of system regulated costs, market prices, level of adequacy, efficiency and generation plants' cost recovery derived from the implementation of the CRM in the power system. A **sensitivity analysis** will be carried out of the most significant variables from a regulatory standpoint.

Finally, the results obtained in the simulations will **be assessed and discussed** in order to draw consistent conclusions from the study. The **main findings** will be presented as well as possible **future lines of research** arising from it.

I.5. STRUCTURE OF THE REPORT

This master thesis is composed of 7 chapter, each of one related with one different topic but all correlated with the next following a studied order.

1. **Chapter I** is the introductory part, which intends to introduce the lector into the study developed in this master's thesis, i.e. 'Assessment of alternative designs of capacity remuneration mechanisms in the Spanish power system in the 2030 horizon'. What are the motivations to do this study, the objectives aimed and the challenges are presented.
2. **Chapter II** presents the objective of implementing a CRM as well as the assessment needed so as to measure the magnitude of the necessity of this mechanism if they are really needed. For this purpose, EC guidelines on this matter are introduce, given that Spain, as a member state (MS) should follow them.
3. **Chapter III** focuses on the study of the range of CRM choices that regulators face so as to address the identified SoS problem in a cost-efficient manner. The results of a deep study of the State of the Art in the field of CRM design and implementation are presented. With the objective of acquiring a deep knowledge of the main issues regarding the implementation of CRM so as to propose a suitable design of CRM for the Spanish power sector.
4. **Chapter IV** is focused on the specific experience of the Spanish electricity sector with CRM. Initially, the specific experience of the Spanish electricity sector with CRM is described for then provide a critical assessment of these mechanisms. It is also explained which is the current situation of the Spanish power sector, with the objective of identify which is the specific SoS issue that must be face when designing a new CRM.
5. **Chapter V** measure the needs that must be addressed by the CRM under three plausible scenarios resulting from the future uncertainty by means of a wholesale market model. Once this gap has been properly quantified, 2 alternative CRM will be design as alternatives to address the Spanish SoS supply issue. The method followed for the assessment of the performance of this alternatives is also introduce.
6. **Chapter VI** presents the assessment of the two alternatives designed. It is done in terms of energy cost for consumers, contribution to the system regulated costs of the mechanisms and cost recovery of generators.
7. **Chapter VI**I provides the lector with the main conclusion of the study as well as some limitation in the study and derived lines of research.

CHAPTER II: State of the Art

In this chapter, the definition of a CRM is presented as well as the consideration that need to be taken into account before implementing this public intervention. The objective is to identify and better understand what the issue that a CRM intends to address is. This will be the starting point for designing a targeted and cost-efficient CRM afterwards. For this purpose:

- Section 1 introduces the objectives of CRM as well as when this kind of regulatory intervention is justified.
- Section 2 focused on guidelines on the designed at European level, that Spain, as a Member State (MS) has to followed.

II.1. EVALUATION OF THE NECESSITY OF CRM

The uncertainty about future framework conditions and different views about policy intervention had motivated the unveil of two opposite beliefs: on one side, those who supported the energy-only market and linked its flawed outcomes to future uncertainty; on the other hand, those who defended the permanent necessity of CRM for yielding efficient economic signals to market agents. However, in the last years, the second belief is increasing in adepts; even those who were firmly confident on the efficiency of energy-only markets mechanisms are considering or have already implemented mechanisms to guarantee Security of Supply in their systems.

In the following sections, the objective of a CRM is discussed as well as the rationale behind its implementation.

II.1.1. Objective of CRM

The ultimate objective of CRM is to guarantee security of supply (hereinafter, **SoS**) in the medium and long-term. According to (Pérez-Arriaga, 2013), these timeframes are referred to as the 'firmness' and 'adequacy' dimensions of the SoS issue, leaving aside the security dimension (from short term to real time issue) and the strategic expansion policy dimension (very long-term).

Therefore, it can be said that CRMs seek (i) to guarantee the ability of already installed plants to meet the existing demand (i.e. firmness) and (ii) to increase investments in generation capacity and postpone decommissioning of plants so as to meet demand in the long term (i.e. adequacy).

II.1.1.1. *The power market failure and the missing money problem*

In a competitive market where demand is sensitive to prices and in the absence of economies of scale in generation, the market price is sufficient to cover the total costs (i.e. variable and fixed) of generating units whose investment is perfectly adapted to the existing demand and to the existence of the remaining generation plants (C.Batlle, 2007). The market price will reach values as high as those that consumers who value electricity the most would be willing to pay before reducing their consumption, i.e. the Value of Lost Load (hereafter, **VoLL**)[1].

Consequently, in this ideal situation the spot price may certainly reach very high levels, as high as an elastic demand would permit. On the other hand, generators would ideally be willing to

[1] VoLL reflects only the average opportunity cost that consumers place on electricity consumption. Given that consumers value differently the electricity supply, this average value do not eventually represent exactly all consumers' willingness (Peter Cramton, 2013).

install as much capacity as necessary to cover the demand and receive those high revenues. However, this is not agents' behaviour in the real world. Consumers and generators are risk-averse; in other words, consumers want an excess of installed capacity in order to hedge the risk of high prices, whereas generators are prone to install less capacity so as to avoid low prices scenarios. A taxonomy of this problem can be observed in Figure 1:

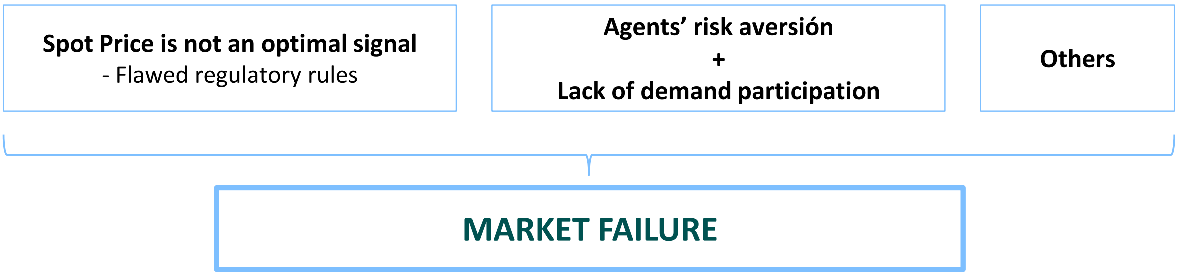


Figure 1. The market failure dimensions. Source. MEPI lecture.

Furthermore, given that demand does not react to those high prices neither in the short nor in the long term, regulators seek to protect them by establishing regulatory measures such as price caps. When price caps are introduced in a perfectly adapted generation mix, the "missing money problem" arises. This entails, as shown in Figure 2, that the income of peaking units obtained from the market is not enough for recovering their fixed costs.

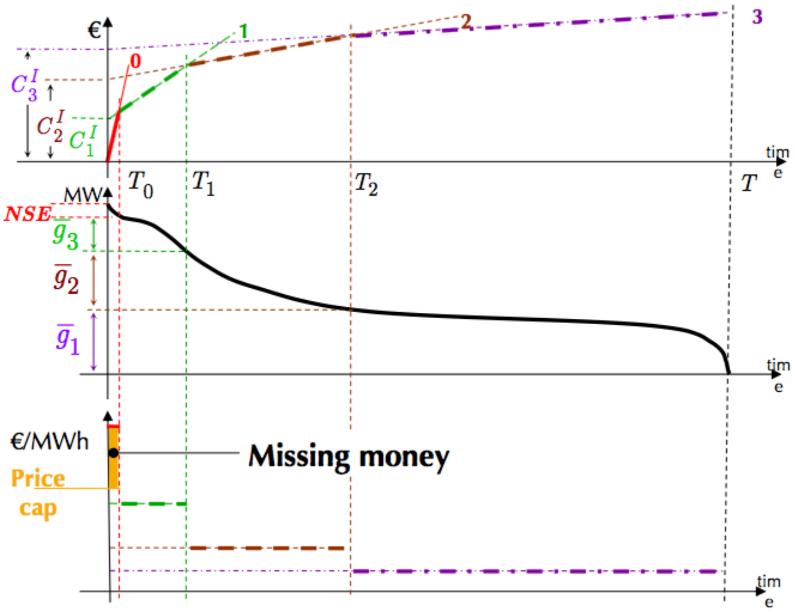


Figure 2. Representation of the missing money problem in perfectly adapted generation mix with a price cap. Source: Master in the Electric Power Industry lecture.

Price caps would supposedly not undermine the price signals to generators if linked to the VoLL.[2] According to (Peter Cramton, 2013), the market would respond to it by building additional capacity up to the point of the value of capacity for consumers being equal to the cost of new capacity. However, in practice the VoLL is difficult to determine and market power abuse concerns make regulators to set price caps below VoLL (Peter Cramton, 2013).

[2] According to (Peter Cramton, 2013): 'If the regulator manages to set this cap at VoLL, the market will achieve the second-best outcome, which we will, with slight exaggeration, term optimal'.

The 'missing money' may lead generators to mothballing or closing units or, when that is not allowed by the regulator as it is the case in Spain, to high economic losses for marginal units. Obviously, under this scenario of losses, no new marginal units' investment would arise and therefore future adequacy problems may occur. The solution to this problem is the implementation of CRM.

Moreover, the high penetration of RES in the last years, has exacerbated SoS concerns in electricity markets. The wholesale market price has declined significantly thus leading to a relevant drop in the revenues for marginal power plants. This, together with the reduction in hours in which these plant produce, is pushing them out of the market. On the other hand, given the uncertainty and intermittency of this RES technologies, scenarios with low production of these technologies, hydro generation scarcity and high demand may arise. Consequently, back up generation may be needed to meet demand which should be flexible and available in order to avoid risk of curtailments. These requirements are usually only met by thermal plants like gas-fired power plants. Which again leads the regulator to consider the implementation of CRM to incentivize these plants to be available when needed.

In conclusion, in the discussion about whether the energy-only-market in capable to ensure SoS in the short, medium and long term, the existence of a market failure is increasingly being acknowledge (Carlos Batlle, 2007). This is reflected in most power systems worldwide having in place or planning to implement CRM in their markets.

II.1.2. **Assessment of the need for the implementation of CRM**

The outcome of an adequacy assessment should be the determination of the optimal future level of capacity as well as the proper mix of capacity that will provide it. Such an assessment can in particular allow a clear identification of the gap between the capacity needed to ensure SoS and the capacity which the market is likely to deliver in absence of regulatory intervention.

For this aimed, the outcome of an adequacy assessment should be compared to a pre-determined value called 'reliability standard'. This value is set at a level that is considered appropriate to ensure SoS and reaching it should be the objective of the implementation of CRM.

In this vein, there are several methodologies for assessing the level of adequacy that a system presents depending on the reliability standard that has been stablish. Next section introduces some them.

II.1.2.1. *Adequacy assessment methodologies*

There are several adequacy assessment methodologies in order to evaluate the capability of the generating capacity and mix to meet demand in all times. The system operator is in general in charge of it. The methodologies can be classified as 'deterministic' or 'probabilistic' as figure x shows.

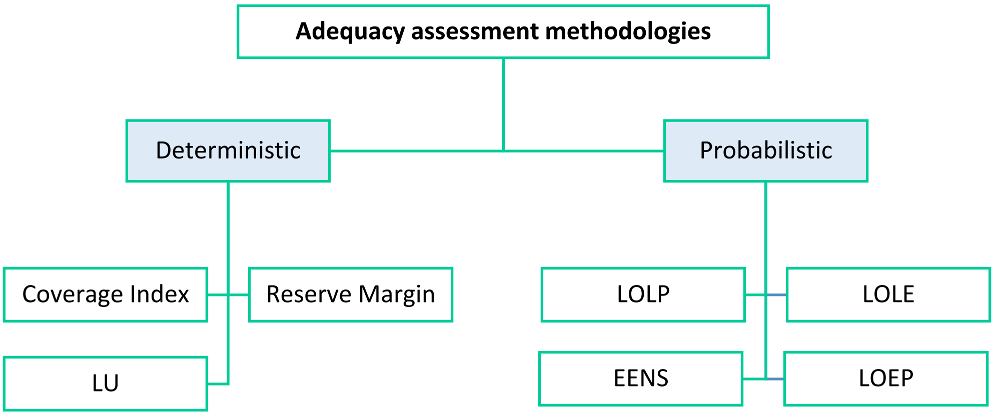


Figure 3. Classification of adequacy assessment methodologies.

Deterministic approaches are simple methods that compare generation capacity with the peak demand in a specific moment in time. They reflect the average behaviour of the supply continuity without considering stochasticity. Specifically, there are three well-known indices that describe in a deterministic way the adequacy of a system: the Coverage Index (CI), the Reserve Margin (RM) and the Largest Unit (LU) which are defined as follows (International Atomic Energy Agency, 1984):

- $CI[p.u.] = \frac{\sum Available\ Generation}{Max\ Peak\ Demand}$
- $RM[p.u.] = \frac{Available\ generation - Max\ Peak\ Demand}{Max\ Peak\ Demand}$
- $LU[p.u.] = \frac{RM[MW]}{Largest\ Unit[MW]}$

The *available generation* is usually calculated as the product of the installed capacity times an expected availability rate calculated taken into account historical availability values of each technology. This assignment of expected contribution of capacity is called de-rating and is intended to improve the accuracy of the determination of the contribution. However, deterministic approaches should be carefully analysed, because they might conceal possible internal grid congestions.

Probabilistic approaches consists of more complex models that consider a wide range of variables under different possible future scenarios, e.g. the likelihood of failures, the variation in demand, the increase in penetration of RES, etc. They are more complex and require more information to be computed that deterministic methods, but in exchange for it they offer more and better information than deterministic approaches. As Figure 3shows, there are several ways to measure the adequacy of a system.

The Loss of Load Probability (LOLP) expresses the likelihood that supply does not meet demand. It is usually expressed in terms of day (or hours) per year:

$$LOLP\ \left({}^{days}/_{year}\right) = \frac{LOLE}{365\ days} \quad or \quad LOLP\ \left({}^{hours}/_{year}\right) = \frac{LOLE}{8760\ hours}$$

LOLP is relatively easy to compute for thermal moderated systems (Peter Cramton, 2013). On the other hand, this index does not take into account the quantity of energy that has not been supplied i.e. the Energy Non Served (hereinafter, **ENS**).

For this purpose, the Expected Energy Not Served ($EENS$) index is used. It expresses the expectation of ENS during a year. It can be also expressed in terms of probability of not covering the demand by means of the Loss of Energy Probability (LOEP):

$$LOEP = \frac{EENS(^{MWh}/_{year})}{Total\ demand\ (MWh)}$$

Through the definition of reliability standards based on probabilistic methods, a proper determination of the capacity gap is achieved and better investment signals are sent to market participants so as to achieve the level of SoS targeted. Therefore, a most cost-efficient CRM can be designed. However, the limit or target of this standard has to be carefully set. For this purpose, the use of VoLL is recommended. By using this value, the regulator has a better orientation of where to set the reliability standard according to how much 'reliability' the demand wants and how much it is willing to pay for it. Nevertheless, it should be taken into account that this value has also some imperfections, namely: no all customers have the same VoLL, the same customer may have a variable VoLL (e.g. sleeping vs. working) and it depends on the notice of the curtailment (if any) and possible compensation measures (Peter Cramton, 2013).

II.2. GUIDELINES ON CRM AT EUROPEAN LEVEL

The uncertainty about future framework conditions and the policy intervention on energy markets, had motivated the unveil of two opposite beliefs (see section x). However, in the last years, many MS are considering or have implemented mechanisms to guarantee SoS of their systems. For this reason, the European Commission has realised that the point is to stop discussing about whether or not the energy-only-market is able to guarantee security of the electricity systems and to assume that they are already being implemented across MS and not in the best ways. Unilateral mechanism must be carefully design in order to be not only compatible with the IEM but also to make easier the proper and fully integration aimed.

In this vein, the European authorities and regulators have issued a series of reports that provide guidance when assessing the need for interventions to ensure generation adequacy and in choosing the appropriate method or design of intervention e.g. (European Commission, 2013) (European Commission, 2014a) (European Commission, 2016a) (DG ENER, COWI, 2013) (ENTSOe, 2015), (ACER, 2013), (ENTSOe, 2015) (EURELECTRIC, 2015b) and (CEER, 2013), According to (European Commission, 2013): 'In line with Article 34 TFEU and the Electricity Directive, Member States, when intervening to ensure generation adequacy, should choose the intervention which least distorts cross border trade and the effective functioning of the internal electricity market. Such an approach will help ensure that interventions are also cost effective'. Moreover, they all state that they should be necessary, non-discriminatory and proportional, while not distorting XB trade and do not hindrance the implementation of a fully integrated IEM.

II.2.1. **European Commission guidelines**

Main principles of state interventions

In words of EC, solving these SoS problems should be done as cost-effectively as possible and avoiding distortion in the market (European Commission, 2016a) by following the principles specified in the Guidelines on State aid for environmental protection and energy 2014-2020 ('EEAG') (European Commission, 2014a). When a MS notifies the implementation of a CRM, EC will assess the compatibility of capacity mechanisms with State aid rules[3]. The main principles that must be follow when considering a state intervention are:

- Necessity

It means that an objective in depth gap analysis must be done in order to demonstrate that there is an actual need of regulatory intervention. As specified in the paragraph (206) of the Guidelines on State aid for environmental protection and energy (European Commission, 2014a) the Commission will consider the following factors: (i) to what extent a market failure leads to a sub-optimal provision of the necessary infrastructure; (ii) to what extent the infrastructure is open to third party access and subject to tariff regulation; and (iii) to what extent the project contributes to the Union's security of energy supply.

- Appropriateness

It refers to the requirement of analysing potential alternative measure before determining the appropriate proceeding. The Commission considers that 'tariffs are the appropriate primary means to fund energy infrastructure', however, it assumes that market failures derive from regulatory interventions (such as price caps) prevent from translate the costs onto end users through tariff, so other possibilities should be considered.

- Proportionality

As specified by the Commission 'The aid amount must be limited to the minimum needed to achieve the infrastructure objectives sought. For aid to infrastructure, the counterfactual scenario is presumed to be the situation in which the project would not take place. The eligible cost is therefore the funding gap' (European Commission, 2014a). In other words, the implementation of the CRM should not increase system and consumers' costs.

According to the EC, the measure is proportional when it meets the following conditions: i) the compensation allows beneficiaries to earn a reasonable rate of return, which basically means that the measure should be designed as a competitive bidding process on the basis of clear, transparent and non-discriminatory criteria; ii) The measure should also have built-in mechanisms to ensure that windfall profits cannot arise and iii) The measure should ensure that the price paid for availability tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded (European Commission, 2014a).

- Avoidance of undue negative effects on competition and trade

As any public intervention in the market, a CRM has the potential to distort free competition, so the design should be done in such a way as to minimize potential distortions to competition and trade in electricity markets.

For this purpose, the measure should be opened to any capacity which can effectively contribute to addressing the generation adequacy problem taking into account that (paragraph 232 of (EC, 2013a): i) when it is technically and physically possible, the CRM should be open to all capacity providers; ii) any restriction is only justified on the basis of insufficient technical performance, iii) sufficient participation is necessary in order to release a competitive capacity price, iv) any measure that undermine the well-functioning of the IEM (export restrictions, price caps, bidding restrictions) should be avoided.

Furthermore, the measure should (paragraph 233 of (EC, 2013a)): i) not reduce the incentives to invest in interconnectors, ii) not undermine market coupling; iii) not undermine investment

[3] An example of this compatibility assessment is available at: http://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf

decisions that preceded the introduction of the measure; iv) not unduly strengthen market dominance and v) give preference to low-carbon technologies in case of equivalent technical and economic parameters.

These principles will be further developed in the following CHAPTER III: , given that once alternatives to the public intervention has been weighed up but rejected, it starts the phase of designing carefully the CRM that is appropriate not only to meet the national capacity requirements but also is in line with the Energy Union's Policy.

The state aid sector inquiry about CRM
In this line, the European Commission (EC) launched in April 2015 a state aid sector inquiry about CRM and the results has been published: "Interim Report of the Sector Inquiry on Capacity Mechanism" (European Commission, 2016a). The main purpose of this inquiry is to extract conclusions about whether the different CRM already implemented (or planned to be implemented) are able to ensure capacity adequacy and firmness without distorting competition and trade in the IEM. It also stands up for assessing the necessity of these mechanisms cautiously and if needed, they should be design in order to be targeted, market-oriented and cost-effective.

II.2.1.1. *Justification of intervention*
The EC states that a CRM should only be implemented in case of true necessity of enhancing SoS. For this aim, the EC has released a guidance to MS for carrying out an objective in depth assessment of this generation adequacy need. The outcome of this assessment should be the determination of the optimal future level of capacity as well as the proper mix of capacity that will provide it.

Given the increasing integration of electricity markets, it is now increasingly difficult to address the issue of generation adequacy on a purely national basis. In this vein, one of the guidance key point is the consideration of the XB dimension. The Member States' generation adequacy assessments need to take into account of existing and forecast interconnector capacity as well as the generation adequacy situation in neighbouring Member States. The quality of this assessment can be improved by integrating the ENTSO-E adequacy analysis as well as the best practices that highlights and must be consistent with Union policy on Energy and on the environment[4].

Such an assessment can in particular allow a clear identification of the gap between the capacity needed to ensure SoS and the capacity which the market is likely to deliver in absence of public intervention. Moreover, if contribution of cross border capacity is not appropriately considered when assessing adequacy, lead to over-investment in capacity on the member state implementing the mechanism and therefore, an unfavourable impact into EU consumers.

The following Table 1shows the reliability index used by several Member States. As it is observed, there is a tendency to used probabilistic method but still not many of them link it with the VOLL. According to the European Commission: 'Linking the reliability standard to the level of capacity that reflects the maximum value consumers place on being supplied with electricity, means that an economic efficient level of protection is set and that expensive overprotection is avoided' (EC, 2016b).

[4] In particular, the following pieces of legislation are relevant: Regulation (EU) no. 347/20138 (the Energy Infrastructure Regulation) the EU emission trading system, energy efficiency measures under Directive 2009/125/EC10 (Eco-design Directive) and Directive 2010/30/EU11 (the eco labelling Directive), and the implementation of Directive 2012/27/EU12 (the Energy Efficiency Directive) (European Commission, 2014a).

Table 1. Adequacy assessment carried out by several Member states (EC, 2016b).

Country	Y/N	Who?	What?
Belgium	Y	TSO	Probabilistic assessment based on LOLE
Denmark	Y	TSO	EENS, LOLE and LOLP
France	Y	TSO	LOLE
Germany	Y	TSO + NRA	Calculation of EENS, LOLE, LOLP and Capacity Margin
Ireland	Y	TSO + NRA	Probabilistic assessment based primarily on LOLE
Italy	Y	TSO	EENS, LOLE, LOLP and Capacity Margin are calculated
Poland	Y	TSO	Capacity Margin
Portugal	Y	TSO + Gov	Load Supply Index (supply/demand per hour)
Spain	Y	TSO	Coverage Index*
Sweden	Y	TSO	EENS, LOLE and LOLP are measured

* In the reference, it is written 'Capacity margin' however, it is preferred to specify that is a Coverage Index what is calculated.

II.2.1.2. *Consideration of alternatives*

Once the generation adequacy problem has been identified, before deciding to support power generators by CRM, other alternatives to encompass the problem should be weighed up. In particular, the potential role of demand side response and storage should be considered as an approach to reduce peak demand requirement in a cost-effective way. In this line, the expansion on XB interconnection capacity would also lead to alleviate national SoS concerns, not only by bringing electricity when scarcity but also by allowing exports from markets with overcapacity. In this last case, it is very important that the CRM is not implicitly aimed at compensate operators for lost income because of bad investment decisions. Allow mothballing is an option that maybe could be taken into account when some inefficient plants are being kept in the system.

II.2.1.3. *Specific principles regarding CRM*

II.2.1.3.1. Participation in the mechanism

In the following Table 2, the principles that the European Commission specifies with regard to participation in the mechanism are shown:

Table 2: EC's principles on eligibility criteria. Source: Own elaboration from (EC, 2013a).

1	Open capacity mechanisms to demand side participation and fully take account of their particular characteristics
2	Ensure consistency with decarbonisation objectives to avoid the lock in effect of new high carbon generation capacity*.
3	Open capacity mechanisms to new and existing generation capacity
4	Base restrictions on participation in a mechanism to ensure generation adequacy on the technical performance required to fill the identified adequacy gap and not on predefined technology types
5	Open capacity mechanism to cross-border interconnectors and to foreign capacity provider and demand response.

*It refers to not selectively exclude specific generation technologies from a capacity mechanism or favouring others within the mechanism as it could be targeted capacity mechanism to thermal plants.

These guidelines are aiming at ensuring that the implementation of the CRM will be cost-effective and in line with Union policy on the environment.

Regarding the point 4 of Table 1 , it refers to those situations when it is suggested that the capacity need can be better addressed by a specific technology. Therefore, in order to be more cost-effective and less distortionary to the internal market, the choice of technology should not be established by the public authority but base any restrictions on performance specifications. For example, the ability to deliver electricity at short notice or within certain time periods where generation adequacy concerns are highest (European Commission, 2013).

Other possibilities to ensure cost-effectiveness is opening the capacity mechanism to retrofitting investments without discrimination with respect to new investments (point 2 and 3), the potential contribution of demand side participation (point 1), and accept the eligibility of cross border capacities providers and interconnectors (point 5). The latter characteristic

II.2.1.3.2. Cross border participation

As stated in the Electricity Security of Supply Directive, MS are not allow to discriminate between national and cross border contracts. The underlying reasons of this prohibition is the distortion of investment signals that individual CRM introduced. For instance, implementing them asymmetrically may displace imports when there is scarcity and excess of production in a neighbour country. With the consequent deterrent of the financial viability of generation capacity. For this reason, MS should be allowed to participate in any CRM as far as they can effectively contribute to the SoS of the system in question.

The maximum capacity that will be able to participate in a foreign capacity market is the interconnector capacity. The allocation of its capacity demanded could be manage by the TSOs separately from the normal allocation process or, alternatively, long term contracts can be signed, while assuring compatibility with market coupling.

Other issue that requires special attention when designing a CRM is the 'Double counting' of interconnectors or foreign capacity providers, but not remunerating them is not an option since it would not incentivise investments in interconnectors. EC recognises the difficulty of accounting for XB capacity trades. For addressing this hindrance contribution of imports should be included in any capacity adequacy assessment.

Table 3 collects the main recommendations related to cross border participation in national CRMs:

Table 3: EC design principles on CRM related to cross border participation. Source: Own elaboration from (EC, 2013a).

1	CRM should be open to all capacity which can effectively contribute to meeting the required generation adequacy standard, including from other MS.
2	Participation of cross border capacity should be allowed based on holding of (financial or physical) interconnection capacity rights, or implement reliability options which ensure that participants are incentivised to hold capacity rights.
3	If the security of supply benefit of electricity imports can only be accounted for implicitly, this benefit should be calculated and these funds used in the development of additional interconnection capacity
4	Cooperate between Member States considering intervention is required to examine the potential of implementing cross border mechanisms

Given the relevance given to this topic, a deeper analysis is done in the following III.3. .

II.2.1.3.3. Time bound intervention

EC highlights the critical importance of time term when designing a CRM. Specifically it declares that lead times should be enough so as to build a new generation plant or implement a DSR programme or retrofitting existing plants.

With the regard to the contract duration, it states that it should be, in any case, shorter than the economic life of the capacity so as not to distort the market in the long term. In this vein, it favours capacity market because they allow to differentiate the contract duration for different types of capacity provider. However, the auction procedure will have to be carefully design so as to avoid overcompensation.

Also for avoiding overcompensation and/or over-procurement, which would put a significant burden to system regulated cost, the mechanisms should be design in a way that allows the price of the capacity to fall to zero when reaching the reliability standard aimed. For this purpose, also market-based mechanism are preferred.

Regarding the time of application of the CRM, EC recommends a frequent regulatory supervision of the performance of the mechanism so as to address the particular problem for which it was implement. Assess the time duration of the mechanism is required.

The following Table 4 summarizes the previous design guidelines:

Table 4. EC design principles on CRM related with time terms. Source: Own elaboration from (EC, 2013a).

1	The lead time for a capacity mechanism should correspond to the time needed to realise new investments, that is 2-4 years
2	The contract duration should be shorter than the economic life of the capacity provider
3	CRM should allow the price of the capacity product to fall to zero as market failures are addressed
4	Regular review of the performance of the mechanism should be carried out

II.2.1.3.4. Avoiding distortions of competition and trade

The difficulty to address the issue of generation adequacy on a purely national basis increases along with the increment of the integration of electricity markets throughout Europe. As state by EC, the introduction of a CRM should not jeopardise the benefits of the IEM. For this reason, any limitation to participate in the market coupling system or balancing markets should be eliminated. For instance, the reservation of capacity the own national usage.

In this line, implicit price cap released by the strike of reliability option mechanisms requires special attention and it should be set high enough in order not to affect the signals of scarcity released by prices in normal market operation.

Regarding the penalties applied to CRM contract-holders when they fail to meet their obligations, they should be design so as to foster availability while avoiding market inefficient outcome such as overbidding[5] or underbidding[6].

These guidelines aimed at not distorting competition and trade in a well-functioning IEM are summarized in Table 5.

Table 5. EC design principles on CRM for avoiding distortion of competiton and trade. Source: Own elaboration from (EC, 2013a).

1	There should be no procedures to reserve electricity for the domestic market where a capacity mechanism is in place.
2	There should be no export restrictions or surcharges from the operation of capacity mechanisms
3	Price caps or bidding restrictions should not be implemented to counterbalance impact of mechanisms on prices
4	Penalties for non-availability should not lead to inefficient production decisions by operators, reliability strike price options should be significantly above expected market prices
5	Capacity mechanisms should not adversely affect the operation of market coupling, including intra-day and balancing markets.

II.2.2. **Other European Institutions guidelines**

II.2.2.1. *Eurelectric*

Eurelectric defends that a CRM should always value capacity in a competitive market, specifically it states that capacity markets will ensure that only the capacity strictly needed for long-term system adequacy is remunerated. It has studied different options for implementing capacity markets and favours either capacity obligation certificates or capacity auctions, as they affirms that they are most likely to cost-efficiently ensure long-term security of supply. (EURELECTRIC, 2015b).

It considers that the main features that any capacity market should have so at to maximize the cost-efficiency of the method and its market orientation are those shown in Table 6.

Table 6. Fundamental features of capacity market according to Eurelectric (EURELECTRIC, 2015b).

Market-based	The value of the capacity need should be stablished in a competitive market.
Technology-neutral	All types of technologies able to provide firm capacity should be allowed to participate in the mechanism
Open to new and existing plants	Market access should be based on a level playing field between both new and existing firm capacity providers
Regional level	Interdependencies with other markets should be taken into consideration as well as interconnections constraints, as a way of diminishing the economic exigencies of the mechanism.

[5] Generator may untrustworthy bid higher so as not to be dispatch and thus not to face the penalties in case of unavailability.

[6] Generator in a country participating in a foreign capacity remuneration mechanism may bid lower in their system and change the efficient merit order with the aim of avoiding penalties on the other country if they do not provide capacity committed.

Open to generation, demand response and storage	All types of capacity provision throughout the value chain should be able to participate in the market.
The product is "availability", not "energy"	The requirement of the mechanism should be to be available. This availability during stress period could be verified by the actual production of energy or by having participate in the spot market.
The period of obligation should be triggered by high prices in the market	Basing triggering on prices is a good approach from both the physical and the economic point of view, and also facilitates further integration of European capacity markets
A 'firm capacity' certification process is required	The regulator of the TSO should certify the firm capacity that each type of provider can offer. In decentralized models, the capacity provider should decide by itself how much capacity is physically able to commit (so as not face penalties).
The definition of the lead time and the contract duration are critical	Duration is a critical design variable, as it needs to balance certainty for consumers and investors alike with adequate competitive pressure. To optimize existing capacity and to manage possible oversupply, a lead time of 3 to 4 years should be sufficient. The minimum duration of a capacity market should be one year and the design should allow for longer durations if new adequacy investments which are necessary do not materialize.
Right to free exit	Capacity providers should be entitled to freely decide when to operate/mothball/close down their assets if their capacity has not been contracted. To facilitate these decisions, secondary markets should be set up to trade the obligations that capacity providers have entered into with other market participants.

II.2.2.2. *ACER*

The Agency for Cooperation of Energy Regulators (CRM) also pronounces with regard to CRM design in (ACER, 2013) and releases recommendation for those MS implementing or considering to implement CRM in their markets.

The design of a CRM should take into account the existing market structure and its imperfections in order to avoid additional distortions to the functioning of the internal market. For this purpose a thorough impact assessment should be carried out prior to the final design and implementation.

The Agency puts in the spotlight the proper price formation so as to send the proper price signals to the agents. In this line, it recommends in (ACER, 2013) that the scarcity price should be set below VoLL (to reflect scarcity against normal market conditions) but always, above the operating cost of the marginal unit in order not to interfere in the efficient dispatch.

ACER believes that a better coordination of the SoS measures among MS is the way of dealing with the risk of potential distortions to short and long term markets. Additionally, when introducing CRMs, the potential cross-border distortions should be assessed based on a common set of criteria, included in point 5 of Table 7.

Table 7. ACER recommendations on CRM implementation. Source: Own elaboration from (ACER, 2013).

1	Security of supply should be addressed as a regional and pan-European issue so as to maximize the benefits of the IEM and avoid distortionary effects
2	A careful impact assessment has to be accomplished before implementing any CRM including: - Nature of the problem to address - Necessity of the mechanism - Appropriateness of the CRM in terms of well-targeted and durable - How cross border capacity is considered - Possible short-term and long-term distortions - the cost of the mechanism
3	Reliable and efficient price formation should remain a priority when implementing CRM
4	MS coordination and cooperation is required so as to avoid hindrance to the full market integration
5	For avoiding potential distortions to the IEM, it is recommended to: - Harmonize generation adequacy criteria - Implement a common and coordinated approach for assessing SoS - Cross border participation should be allowed - Accompany the introduction of national mechanisms by a sound and detailed impact assessment.

CHAPTER III: **Analysis of alternative CRM designs**

Once an assessment of the generation adequacy situation has been done and it has been concluded that there is a need for the introduction of a form of support for generation capacity, Regulators face a range of choices to design the most suitable CRM to address the identified adequacy problem. In this chapter, the State of the Art in the field of CRM design and implementation is presented. The objective is to acquire a deep knowledge of the main issues regarding the implementation of CRM so as to propose a suitable design of CRM for the Spanish power sector. For this purpose, this chapter is structured as follows:

- In section 1, a classification of the different types of capacity remuneration mechanism is done,
- In section 2 their main design variables are presented
- Section 3 is focused on one specific designing variable which is the possibility of permitting cross border participation in national CRM.
- In section 4, a review of international experiences is perform, so as to acquire a real overview of implementation issues that may arise when implementing a CRM
- The later section 5, is the outcome of the study perform if the previous sections of this chapter. An assessment of the various types of CRM is done that will serve to design the alternatives in the following chapter III.

III.1. ALTERNATIVE CRM DESIGNS

The classification of CRM is not straightforward given that there are different criteria that can be used depending on the choice of variables.

One classification could be the one given by the EC's in his Interim Report on capacity mechanisms (European Commission, 2016a). In the Figure 4 a taxonomy of this classification can be observed. According to it, there are six basic types of CRM grouped into 2 categories: targeted mechanism, only for selected capacity providers, and market-wide mechanisms, which include all types of capacity available. At the same time, the mechanisms can be divided into volume-based mechanism or price-based (or a combination).

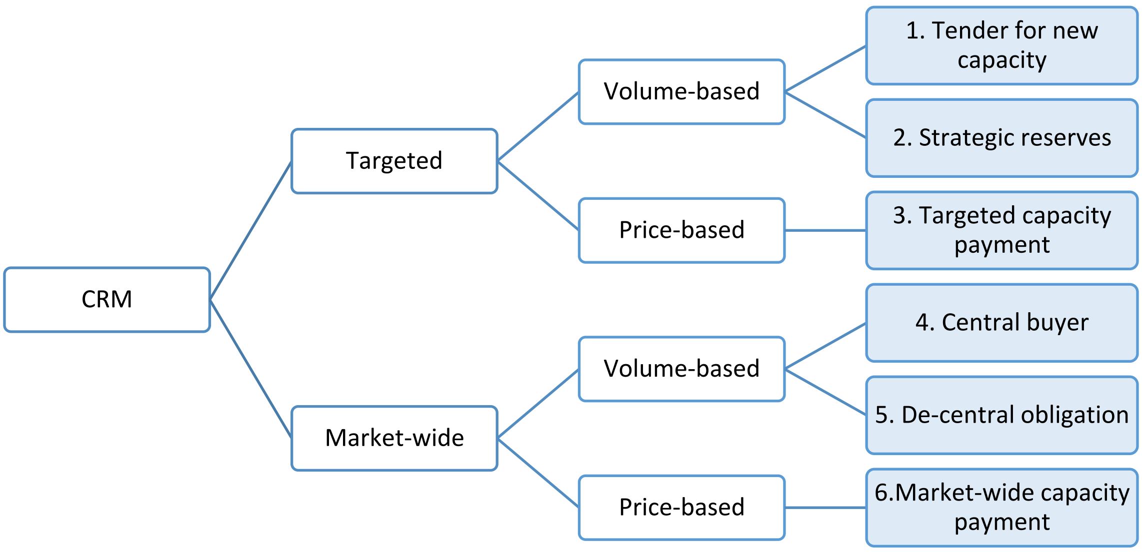


Figure 4. Classification of capacity remuneration mechanisms (EC, 2016b).

However, the classification made by the DG ENER (DG ENER, COWI, 2013) is better suited for this study given that it leaves more freedom for designing the remaining variables of the mechanism as explained in section III.2. .

This classification groups the mechanism into 4 main categories:

i. **Strategic reserves**, in which targeted capacity providers are compensated for keeping capacity reserve that cannot be offered in the market.
ii. **Capacity payments**, in which capacity providers receive a direct fixed payment set administratively.
iii. **Capacity markets**, consisting on the definition of a capacity requirement in which the price is determined by the equilibrium of supply and demand.
iv. **Tenders** for new capacity

Figure 5 shows the classification considered. A more detailed explanation of these mechanisms is given in the next paragraphs.

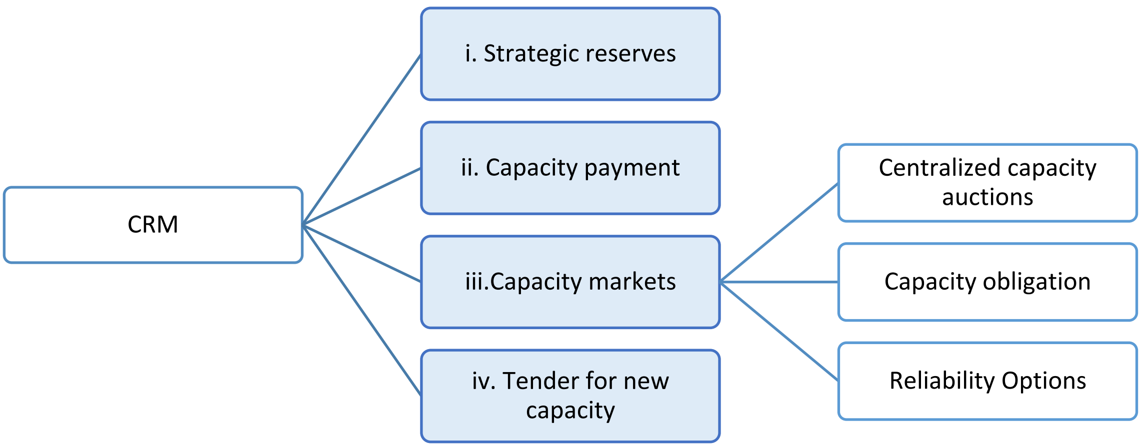


Figure 5. Classification of CRM used in this study.

III.1.1. **Strategic reserves**

These are capacity reserves that do not participate in the market and are only used by the system operator in case of necessity. They commit (by a long term contract or in a year to year basis) to be available in exchange for a payment agreed in a tendering procedure for a specified amount of capacity (in MW).

In other words, there is a commitment in terms of a certain amount of MW that cannot participate in the wholesale market and must be available when called upon. The compensation scheme may involve direct payments, payments in the form of an option or mixed forms (DG ENER, COWI, 2013). This capacity can be provided by existing units or by installing specific generation reserves for this purpose.

Interruptibility systems are also considered strategic reserves, having the particularity that the firm capacity is obtain by demand shedding. However, this committed capacity can be bid into the wholesale market as long as it reduces demand when called upon.

III.1.2. **Capacity payments**

Generally, this approach consists in directly remunerating generating units for being available, according to its firm capacity (€/MW). Apart from this income, they can participate in the wholesale market (this is the main difference with strategic reserves).

Capacity payments allow for a great flexibility with regard to the definition of the eligible providers, that is to say, it allows to target the remuneration to the capacity suppliers depending on the preferable characteristic, such as whether they are base or peak load capacity, if they are existing or new plants or the type of technology. Demand side resources are typically not eligible for capacity payments.

This mechanism can be both implemented for attracting new investments in capacity and/or for fostering availability of plants at time of scarcity. Therefore, in the first case, the payment should be high enough for making new units to recover the portion of the annualized investments cost non-recoverable in the market. If the capacity payment intends to remunerate availability, the payment should be able to cover at least the avoidable fixed cost if the plant would mothball, e.g. the operational fixed costs and the gas tariff in the case of a CCGT. Therefore, one benefit of capacity payments is that can simultaneously incentivize availability of existing units and new capacity investments.

Capacity payments can consist of: i) a fixed payment for all capacity types participating in the mechanism which can be fixed in a year by year basis or in the form of a long term contract; or ii) a dynamic capacity payment, where the level of remuneration changes depending on the actual level of capacity needed and tends to zero if there is no more needs of capacity.

There are two possibilities of setting the capacity requirement: on the one hand, the price paid for the capacity provided and the quantity needed are set administratively. On the other hand, it is considered to be a price-based mechanism when the regulatory body only determines the level of payment and is the market which adjusts the capacity.

The definition of the level of the payment is the major difficulty of this mechanism and usually its most relevant drawback; moreover, there is no guarantee of protection against price spikes or market power abuse.

III.1.3. **Capacity markets**

Capacity markets are a volume-based mechanism (targeted or market-wide) where a capacity requirement is set at the outset and the price is the result of a market mechanism. It should be noticed that the capacity product is totally differentiated from the 'electricity' product and therefore an independent market is created. Three types of capacity market can be differentiated. These are:

III.1.3.1.1. Centralized capacity auctions

The centralized capacity auctions, also called central buyer models, are capacity markets in which a central buyer (typically the system operator) acquires the capacity that consumers need for supplying their demand plus a margin. There is an auction where capacity providers bid what they expect to receive for providing the firm capacity required and the central buyer pays for it to the benefit of the consumers. Even if the payment has the form of an annual payment in €/kW, it differs with respect to the capacity payment in that the level of remuneration is not set administratively but it is the result of the auction, therefore the clearing price reflects the true value of the capacity that it is being provided.

III.1.3.1.2. Reliability options

Reliability options are similar to centralized capacity auctions but differing in the design of the capacity contract. It implies, firstly, a fixed payment (i.e. a premium) that the capacity provider receives for the right given to the buyer to exert the call option[7].

The holder of the reliability option contract can bid its energy into the market and receives the spot price, as far as it is lower than the so called *strike price*. Conversely, if the spot price results higher than the strike, the capacity provider must pay to the buyer the difference between these prices. In some cases, the central buyer only acquires capacity on behalf of the domestic demand and other buyers can participate in the market (e.g. large industrial customers) (Carlos Batlle, 2010).

The strike price, also known as 'scarcity' price, is set ex-ante by the central buyer for representing that there is a stress situation and scarcity of energy may occur. It is set at a price that is slightly higher than the marginal cost of the most expensive unit of the system (Bidwell, 2005), in such a way that the mechanism is activated only when there is a risk of shortage. It is recommended that 'it should not be so high to allow a peaking unit to recover all its operating costs just in one hour' (Carlos Vázquez, 2003).

Its value does not change the remuneration of the generators since they would ask a premium so as to net-balance the strike and recover their costs. However, it does affect the market price since generators will bid a bit lower than the strike price in order to assure they will be producing in case of the spot price overpasses the strike so as not to be penalized. For this reason, the strike price acts somehow as a price cap to the market (as far as peaking units with no RO contract are not dispatched) and this interference should be avoided under normal market functioning. According to (Carlos Vázquez, 2003), this lead to set the strike price according to 'the variable cost of the most expensive peaking unit that might be reasonably required to serve load'. Additionally, the authors propose to increase this value a 10-15% above, so as to avoid the negative impact of being underestimated. If there is risk of market power, setting the strike price lower could be considered.

Other characteristic that should be considered when setting the level of the strike price is that this value will have to be updated, owing to the fact that the marginal cost of the reference peaking unit will change through time, due to fuel prices or inflation. On the other hand, if it is updated too frequently, uncertainty for generators will increase and so they might lose incentives to participate in the mechanism. For this reason, it is suggested to use a public formula linked to fuel prices and RPI (Carlos Vázquez, 2003).

Generally, there is physical delivery agreed in the contract so, the provider is willing to supply in those scarcity situations given that a penalty should be paid in case of not being available. A graphic explanation of this mechanism can be observed in Figure 6.

[7] A call option is an agreement that gives an investor (in this case, the central buyer) the right, but not the obligation to buy a stock, bond, commodity or other instrument (in this case, the production of a certain capacity) at a specified price (the strike price) within a specific time period (in this case, period when the reference price is over the strike price).

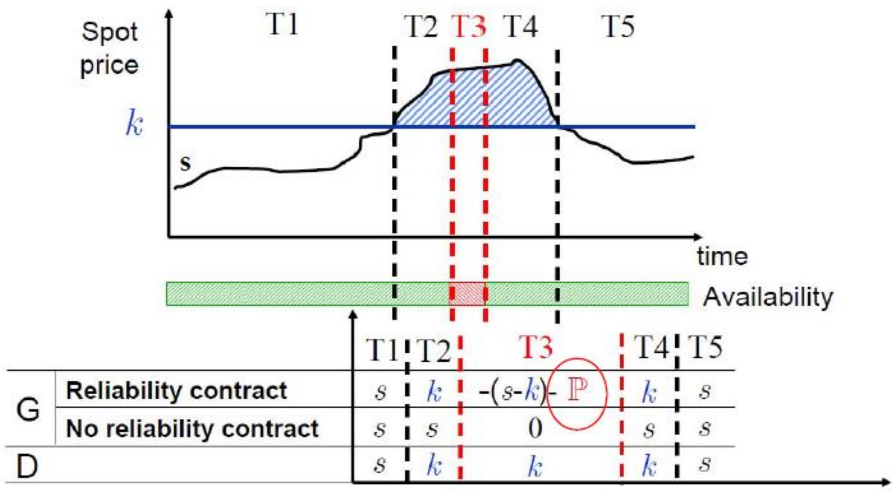


Figure 6. Physical reliability option. Source: (Carlos Vázquez, 2003).

In case that physical delivery and firm supply are not contemplated in the contract, referred as a financial reliability option (no penalty), also a financial entity could be provider of this product. In this way both demand and generation hedges price risk.

The main problem of this type of CRM is the risk of market abuse if not enough capacity participate in the capacity market. The risk of price manipulation decreases if a wide capacity provision could be guaranteed (Carlos Batlle, 2007), for this reason, allowing potential new entry generators to bid against existing ones increases the level of competition and reduces the opportunities to exercise market power abuse (Bidwell, 2005). Other tool used in order to prevent consumer from high prices owing to market abuse is the establishment of a price cap in the demand curve (European Commission, 2014b).

Other problem that may arise is free-riding, when the central buyer only buys capacity on behalf of household demand but also large customers are benefited. This can be solved by a proper definition of the product, for example by charging large customers a higher cost for their consumption when free-riding (Carlos Batlle, 2010).

III.1.3.1.3. Capacity obligations

Under this mechanism, the capacity requirement is imposed on Load Serving Entities (LSEs), which have the obligation to buy the amount of energy demanded by their consumers plus a reliability margin (determined by a regulatory authority). Capacity contracted under capacity obligations is expected to bid the generation into the wholesale market or trade it bilaterally, and in particular, in scarcity situations.

The obligation of the suppliers can take the form of a capacity certificate, the ownership of generation plants, bilateral contracts or the capacity can be bought in the market.

In a system with capacity certificates, a market (bilateral or centralized) is created where they are traded between capacity providers and suppliers. The capacity provider has to make available enough capacity certificates in the market and the suppliers must hold enough certificates for meeting demand obligations. Capacity providers are paid for the issue of capacity certificates (or bilateral contract) and the LSEs pass on the costs of the certificates purchased to their customers. In return, the generator is required to make the contracted capacity available to the market in shortage periods, which may be defined in terms of a threshold price or by an ex ante communication from the TSO. If they fail to make available the contracted capacity, penalties are applied.

Capacity obligation schemes may apply to the present volume of load served or to volumes expected to be served in the future. In the former case contracting for capacity may be done on a "spot" basis, to adjust their position and fulfil the present time obligations. In case of future obligations, the capacity market assimilates to a forward market where LSEs conclude long term contracts with generators for their expected future volume of sales. If these long term contracts do not arise from the market, sufficient new capacity may not occur (EURELECTRIC, 2015b).

The main advantage of a model of capacity obligation in the form of standardized capacity certificates is the flexibility that it gives to capacity providers and LSEs, owing to the fact that certificates can be traded (in an organized market or bilaterally). Hence, the price for capacity certificates is determined by supply and demand in the market.

III.1.3.2. *Tenders for new capacity*

In tenders for new capacity, long-term contracts are assigned to the awarded generators. These should generally meet specified characteristics, including for example the size, technology type and location. These tenders are limited to new projects, although foreign capacity could be considered (EC, 2016b).

Different criteria could be applied in order to award the capacity contract among the eligible capacity providers such as the minimum price, the lead time needed in order to meet their obligations (time of construction), location of the installation, environmental requirements or contribution to the well-market functioning.

The terms of the contract of the successful beneficiaries can vary widely. Generally, they would receive capacity payments in return for making capacity available or they win a financing contract for the construction of a power plant and stop receiving payments once the plant has been built. Other decision in the tender that should be made is whether the capacity providers can participate in the electricity market or should keep their capacity aside. Penalties can be applied if the capacity is not made available when needed or in case of delay on the construction of the installation.

The tenders for new capacity, also known as long term contracts, differ slightly from a capacity market. However it generally depends on the definition that is being considered. In the context of this master thesis, a tender for new capacity differs from the capacity market in the following points:

- The tender for new capacity, is only aimed at new generation capacity and therefore, as a tool to solve a future adequacy problem.
- It is used as a temporary mechanism to solve a specific and not systemic SoS issue. That is to say, when the definition of the usually more complex capacity market is not worthy.

III.2. DESIGN CHARACTERISTICS

III.2.1. Eligibility

The eligibility refers to the choice of who can participate in the capacity mechanism. The mechanism can be open to selected providers of capacity (targeted mechanism) or to all market agents (market-wide mechanisms), however the existing CRM are generally targeted.

The election of the targeted capacity providers will depend on the identified SoS problem and can be made in two ways:

- Explicitly specified which providers can participate in the market.
- Implicitly selected by setting requirements that the capacity providers must comply with to be eligible.

The eligibility criteria are mainly based on:

i. Generation technologies

The eligibility may depend on the kind of technology provider of electricity. It selectively excludes or favours specific generation technologies which are considered as more suitable to hedge the risk of shortage. For instance, if the problem is linked to an intermittent generation mix or to limiting ramps to adapt to sudden changes in demand (or supply), only flexible technologies may be needed. For this reason, usually RES generation is excluded from providing these services and only thermal generation and large hydro is included [8].

As mentioned before, the exclusion could be declared explicitly or rather implicitly by a specific requirement such as:

- Size requirements, which may exclude small generators as RES or storage providers.
- Environmental standards, which may lead to the exclusion of some fossil fuels plants or other pollutant technologies.
- Technical performance, which can explicitly exclude plants with low efficiency or high ramp up/down times. Also the admission can be subject to technologies that can participate in the ancillary services.
- Availability requirements, such as a minimum firm capacity (understood as the expected capacity available in specific periods) which tends to exclude RES generation because of the uncertainty of its production and thus their risk of being penalized.

ii. Demand response

The participation of demand response in CRM would reduce peak demand and therefore the investments needed not only in generation but also in transmission and distribution networks. If participation of demand response is allowed together with generation capacity providers, its remuneration could be subject to its willingness to reduce demand, that it is to say, the value they perceive of the VoLL. Other possibility is to design targeted CRM for demand as it is the case of the so called interruptibility mechanisms.

Requirements in the size of the capacity providers may implicitly exclude demand respondents and so does the lead time between the allocation process and the delivery of capacity. The lead time can be different or equal to the one for generation. In the case of interruptibility schemes, the lead time can vary from one month to years. Other issue to take into account when dealing with demand response is the definition of the product, i.e. unclear methodologies or too low remuneration may lead to lack of participation of agents.

iii. Storage providers

Whether storage can participate in the mechanism as capacity provider should also be considered when designing CRM. Storages can contribute with its flexibility to SoS by storing

[8] Recent capacity remuneration schemes tend to allow RES participation, as the case of French de-central obligation scheme and the UK capacity market.

electricity when it is cheap and abundant, and releasing it in scarcity situations. It can be generally provided rapidly but for short periods.

iv. New vs. existing capacity

Deciding whether to include new capacity, existing capacity or a combination of both will depend on the specific problem that it is aimed to be addressed. For instance, tenders for new capacity explicitly exclude existing generation, whereas strategic reserves usually try to avoid closure or mothballing of existing capacity.

On the other hand, the lead time play a key role when addressing the eligibility of new and/or existing plants, given that if too short it will exclude implicitly plants with high construction periods. The opposite occur when defining the duration of the contract, i.e. too short contracts tends to implicitly prevent new plants from participating.

v. Location

It consists on delimiting the area from which capacity can participate. It can be locally delimited, nationally or regionally (if permits cross border participants). Locational delimitations are useful when dealing with network constraints, given that it ensures that the capacity will be built or made available in particular places. Special attention is required by cross-border (hereinafter, **XB**) locational requirement, for this reasons further details are introduced later on in point III.3.

III.2.1.1. *Eligibility design issues*

Selectivity leads to less competition and therefore, to higher prices of the capacity provided. On the contrary, by reducing eligibility requirement, more competition is fostered and therefore, the SoS requirements can be met at a lower price. Other inconvenient of too selective mechanisms is the so called 'snowball effect'. It makes reference to the fact that implementing a mechanism aimed at a specific type of technology may exclude other providers that need that aid. This may lead to the later implementation of another targeted CRM aimed just at those providers initially excluded.

When deciding which the eligible participants of the mechanism are, other issue that should be taken into account is the correct identification of the SoS problem. If there is a locational problem, it means that the market is failing at sending the proper investment signal for solving either the lack of generation capacity or the lack of interconnection. Therefore, what it is needed is let the market to send the correct investment signal. If there is no time in the medium and short term to solve these problem (e.g. some investments take too much time), then a temporary locational CRM can be contemplated. The objective of this mechanism is generally, to avoid mothballing or closing.

It is important to consider the participation of foreign capacity providers and interconnectors in individual CRM. As explained in detail in next section III.3. when it comes to the European context this exclusion distorts the IEM by creating overcapacity in the country where it is the CRM and less incentive to invest in foreign capacity and interconnectors, and as a result, it implies a higher costs for the overall system (EC, 2016b), (DG ENER, COWI, 2013).

III.2.2. **Allocation process**

Apart from the European Commission in its Sector Inquiry, there are other references (Pérez-Arriaga, 2013), that makes in general terms the classification of CRM according to whether the main objective is to ensure a certain quantity of the ''reliability product'' or if it is the price of the capacity product itself what is set and it is the market what brings the outcome capacity. They are called price-mechanisms and quantity-mechanism respectively. However, in this work it has been preferred left this characteristic defined along with the definition of the 'allocation process' introduced in this section, where we talk about administrative or competitive procedure. This decision comes mainly due to the fact that a combination of these two types of schemes is commonly applied, specifically through the definition of a capacity demand curve. Besides, the following Figure 7 shows schematically how the requirement of capacity may be expressed:

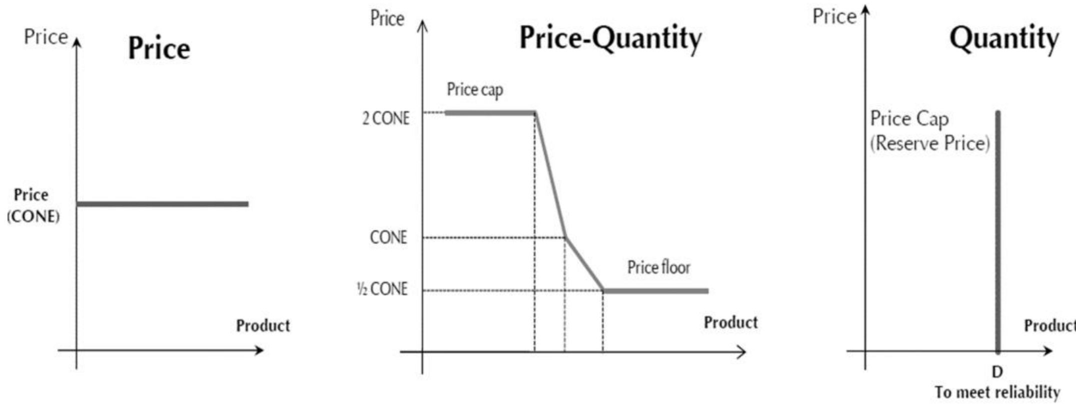


Figure 7. Price-based vs quantity-based mechanism. Source: MEPI lecture.

Through the allocation process, the capacity providers are selected as well as the price that they will receive. If well-designed, an allocation process selects the most cost-effective option from the eligible capacity providers and sets a capacity price that avoids overcompensation (European Commission, 2016a).

This process can be administrative or competitive. The administrative allocation process, implies a non-competitive selection of capacity providers and an ex-ante definition of the remuneration by public authorities (price-based mechanism inFigure 7). In the competitive allocation process, providers are selected through a bidding process which releases also the price of the service (price-quantity mechanism or quantity mechanism in Figure 7).

III.2.2.1. *Administrative process*

In an administrative process, the definition of the price is critical in order to send the right economic signals to investors. If it is too low, not enough capacity will be brought to the system and, on the contrary, too high price will lead to over-procurement. Generally, the problem that arises is the latter, given that regulators tend to set the reliability margins "on the safe side" (DG ENER, COWI, 2013). Furthermore, it has to be considered that it probably will not reflect the real value of the capacity if the price is fixed for all the contract period, that is too say, if more capacity enters the system the necessity of further capacity and thus its value would be reduced. This impact can be softened if the level of remuneration is linked somehow to the evolution of the reliability standard.

III.2.2.2. *Competitive process*

In the case of competitive allocation process, two possible schemes can be applied to determine the selected provider: a central auction and a de-central obligation. In the first type process, capacity needs are set ex ante centrally and then auctioned, in the second one, the capacity is estimated by the suppliers so as to meet an obligation of procuring enough capacity to their customers.

De-central obligations generally follows a quantity-based procedure, where a quantity is set ex-ante and is the market which reveals the price of the capacity. In case of central buyer models, after setting the quantity or a price-quantity curve, the price and the quantity finally provided is obtained with market mechanisms in a competitive manner. An auction is held where the outcome can followed a *Pay-as-bid* rule, if the successful bidders receive the price that they bid, or a *pay-as-clear rule*, in case that all the bidders receive the most expensive bid successful in the auction.

One problem of the competitive allocation processes could be the price volatility derived from the fact that demand and capacity supply are inelastic in short-term. For this reason, taken into account that in long-run demand is a somewhat elastic, the mentioned price-quantity curve can be used (Bidwell, 2005). This price quantity demand curve intends to give flexibility to the amount of capacity to contract depending on the cost. This curve (central representation of Figure 7) generally reflects: (i) the targeted capacity level, (ii) the cost of new entry (CONE), which sets the price at which the target level of capacity would be auctioned, and (iii) a price cap.

III.2.2.3. *Allocation design issues*

When deciding the capacity allocation process, several design issues have to be considered. First of all, it has to be considered that through a competitive allocation process there is no risk of determining a level of remuneration too high or too low given that it is set by market forces. Therefore, it is the best option provided that market power is carefully kept under-control.

The price cap in the auction is set in order to avoid this abuse market power if no enough competition is guaranteed. However, it has to be taken into account that this cap may led agents to bid close to it. In words of (Carlos Vázquez, 2003), 'if the buyer declares a priori which is the maximum price that he considers reasonable, the auction will end up at that price with a high probability'.

In this vein, when setting the level of the price cap it is necessary to pay attention to: firstly, not setting them too high for not incurring in high costs when agents bid close to that cap; and secondly, not setting them too low, because under-procurement may happen if there is not enough competition. Price floor could be also set in order to support new investments without the need for long term contracts[9].

Participation in competitive procedures should be also opened to as much as possible participants so as to effectively foster the competition required. According to (Carlos Batlle, 2010) there is a certain consensus about the desirability of using auctions. Among others reasons because an auction increases competition, it avoids unfair agreements of vertical integrated and it takes advantage of economies of scale.

One special concern is related to the design of specific mechanism for demand respondents as the interruptibility schemes. When the allocation process is administrative, the risk of overcompensation is significantly high. This occurs given that it is difficult to authorities to estimate the real costs that demand incurs when shedding or shifting load.

Other issue that should be carefully considered is the linking of the level of remuneration to a reliability standard in order to send the right economic signals through the duration of the incentive.

[9] This is the reason why the Italian Authorities has include a price floor in its Capacity Remuneration Scheme (EC, 2016b).

III.2.3. Capacity product

The definition of the capacity product consist in determining what the capacity providers must fulfil in return for a remuneration and what happen if they do not perform as required, that is to say, the obligations and penalties.

III.2.3.1.1. Obligations

Generally the obligation is imposed according to the type of CRM selected, but in general terms what has to be defined is:

- **Nature of the obligation**: if a physical delivery or a reduction of demand is required, if the obligations consist in being available or guaranteeing a certain firm capacity (even if not delivered). In the case of the reliability option the requirement is to pay back the difference between the spot price and the strike and in the case of capacity certificates it is mandatory to hold a specified quantity of them. It can be also an obligation to bid capacity in the day ahead market and/or the ancillary services market.
- **Lag period (or lead time)**: it refers to the time between the award of the capacity contract and the beginning of the obligation of providing capacity when called upon (see Figure 8). Short lead times tend to implicitly exclude new generation capacity and, to a lesser extent, new demand response providers, therefore, if new capacity is sought it is usually set according to the time of construction of new plants.
- **Contract duration**: is the duration of the obligations and therefore of the payments. New investments need longer contract durations that existing plants but too long contracts may lead to cost overruns. The type o new capacity also can vary the need of different contract duration, i.e. high capital-intensive investment (such as hydro power plants) would need longer contract terms than a thermal power plant (Carlos Batlle, 2010).
- **Period of obligation:** is the time during which the capacity providers are required to be ready to fulfil their obligations. It can vary from selected hours or days (defined ex ante), seasons like winter or during all the year. The obligation of being available should fall into scarcity periods, so it could be properly reflected by the market price overpassing a certain level (i.e. a strike price)
- **Notice period:** when a capacity mechanism includes a warning or notice, it refers to the time between this and the obligation of being available. It can be fixed ranging from one day to 30 minutes ahead. It can be variable according to the TSO decisions or it may not exist. This last is the case of reliability options contract, where the participants should be ready to operate when the price is getting close to the strike price.
- **Limitations on use**: when the number of hours the service can be used continuously or times the resource can be called upon is limited.
- **Testing:** it refers to the way of checking that the obligations can be met. It can be a precondition of eligibility but also it can be done during the duration of the contract. It should be taken into account that testing could be an entry barrier for demand response providers given that testing generally implies a real curtailment for them.
- **New plants requirement:** generally established in order to assure that the capacity will be built and ready for meeting their obligations on time. It usually means the requirement of collateral in the form of bank guarantees, having a solid business plan and/or present a specified level of creditworthiness.

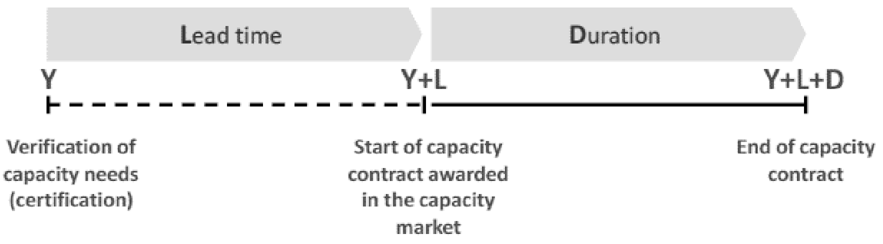


Figure 8. Lead time and contract length in capacity markets (EURELECTRIC, 2015b).

III.2.3.1.2. Penalties

The design of penalties is essential in order to incentivise capacity providers to meet their obligations, namely to be available in scarcity periods. It should not be too low for guaranteeing the objective of supply but not too high, because providers may not be willing to participate in the mechanism if the risk of not meeting their obligation is excessive (EC, 2016b). These values must be set so that they do not interfere with competitive price discovery and at a level not lower than the level corresponding to newly built capacity (EURELECTRIC, 2015b).

The penalties generally apply when the obligation is not met and they can be different depending on what obligation has not been met.

When the delivery obligation is not fulfilled, the penalty usually implies the pay back of a percentage of the remuneration received that can be proportional to the energy not delivered when required. It also can include ranges, in the sense that if a limit is exceeded a different penalty is applied. Non-monetary penalties can be applied as well, such as the loss of the right to be eligible next years or being directly excluded from the mechanism. The penalty regime should reflect a shortage in the system, which usually is revealed by high market prices so the penalty applied could be based on market prices as well.

III.2.3.1.3. Product design issues

When designing the product, it should be taken into account that the SoS might be affected if short time contracts are applied. This is because the risk of some capacity providers increases when the duration of the contract decreases. The contrary occurs with demand side providers, which would be more interested in shorter periods. Also the risk of the participants can be reduced with shorter periods of obligation, given that the providers could plan in a better way their scheduled maintenance. In the same way, limitations on use tend to decrease the risk of participants, with the consequent increase in competition and reduction on costs.

With regard to demand side participation, specific products could be justifiable in order to allow them to play a more significant role in SoS. Firstly, it is necessary to consider different requirements for demand respondents and capacity providers due to the different nature of these sources of capacity, for instance more limitations on their use may lead to its better integration. Moreover, it would be also convenient to differentiate between large certified industries or aggregators (explicit participants) and the demand management of suppliers (implicit participation), given that too strict obligations would be in detriment of implicit demand participation.

Another significant issue is the distortion of market prices. CRM with price caps and remunerating (or penalising) on the basis of energy delivered will more likely distort market prices. This occurs because the capacity will be partly remunerated by capacity mechanisms and the other part by market prices, so the market price will be highly influenced by this proportion. Specifically, dispatching strategic reserves too early may avoid prices to rise till reflect scarcity (implicit price cap) therefore some capacity may not be able to recover their fixed cost and would not be willing to participate in the capacity mechanism next time. These effect, known as 'slippery slope' would certainly increase system costs. One possibility could be dispatch these reserves only when the market has failed so as to allow market prices to increase enough (European Commission, 2016b).

With regard to penalties, if they result to be insufficient it would not incentivise plants to be available when needed but if they are set too high, risk of under procurement arises. Other option when designing penalties could be to consider capacity mechanism penalties as a replacement for electricity scarcity prices given that both provide economic signals to produce or reduce in scarcity situations (European Commission, 2016a). In other words, the penalties could be the return of certain amount of money when the prices have risen over scarcity levels, given that generators have not produced enough so as to avoid that rise (this is the case of a reliability option contract).

III.2.3.2. *Summary of design variables considerations*

Table 8 summarizes the main considerations of the design variables of CRM introduced in the previous sections.

Table 8. Summary of design variables considerations.

ELIGIBILITY	
Key issues	- Selectivity leads to less competition and so, to higher prices and vice versa. Also to a 'snowball effect' risk. - The identification of the SoS problem is essential for designing the eligibility criteria.
Technology requirements: Size, technical performance, environmental standards, availability requirements	- If the problem is an intermittent generation mix, only flexible technologies may be required - Small generators may be excluded, as RES or storage providers. - Fossil fuels plants or other pollutant technologies may be excluded for environmental reasons - High efficiency or low ramp up/down times may be a requisite. - Availability requirements, such as a minimum of firm capacity tends to exclude RES generation.
Demand response	- Remuneration can be subject to VoLL - High size requirement may exclude them - Shorter lead times favour them
Storage providers	- Rapid response but for short period - High size requirement may exclude them
New vs. existing capacity	- Key role of lead time: too short excludes new plants - Too short contract duration excludes new plants
Location	- Locally, nationally or regionally delimited - Locational delimitations are useful when dealing with network constraints - The exclusion of interconnectors and foreign capacity may create overcapacity in the country where the CRM is in place and less incentive to invest in foreign capacity and interconnectors.
ALLOCATION PROCESS	
Key issues	Market power, overcompensation, over-procurement
Administrative	- Critical definition of the price: too high values leads to overinvestments and vice versa. - Usual problem: overinvestment - Impact of a fix price during the contract duration can be softened if it is linked to the actual reliability standard - High risk of overcompensation to demand respondents.
Competitive: central auction de-central obligation	- Price caps can be used in auctions for avoiding market power - Price floors can be used to support new investments - Descending clock auction recommended for fostering competition among new and existing capacity providers - If enough competition, it reveals the true value of capacity - It is recommended to link the level of remuneration to a reliability standard in order to send the right economic signal
CAPACITY PRODUCT	
Key issues	Mainly related with the risk of providers of not meeting their obligations and thus the lack of participation. Key design elements: Lead time, contract duration and penalties.
Obligations	- Nature of obligation: requirement of physical delivery, reduction of demand, holding firm capacity, being available, participate in the DAM, IDs and balancing markets, etc. - Short lead times tend to implicitly exclude new generation. - New investments need longer contract durations but too long may lead to over-costs. Demand respondents are more interested in short periods. - The period of obligation can be defined ex-ante (winter, peak hours…) or by a strike price. - The notice period can be fixed (~1 day to 30 min), variable (set by TSO) or not exist (strike price in RO). - Higher limitations of use may foster participation - Testing: could be an entry barrier for demand response - New plants requirements such as collateral or creditworthiness.
Penalties	- It can be monetary (payback of part of the remuneration) or not (e.g. being excluded from the mechanism) - It can be linked to VoLL - Not too low for guaranteeing the supply needed - Not too high, because it may result too risky for providers to participate.

It has to be taken into account that the selection of the type of CRM as well as their design will vary widely. It will depend mainly on which is the SoS problem that the mechanism intends to address, the existing generation mix and its interaction with existing regulatory measures. A proper definition of the eligibility, allocation process and reliability product are fundamental variables in order to reach the reliability target aimed in a cost-efficient way and without distorting the market.

III.3. ALLOWING CROSS-BORDER PARTICIPATION IN CRM

In words of the EC, excluding foreign capacity from participating in individual CRM *'will lead to overcapacity in the capacity mechanism country, and if each country has a capacity mechanism and does the same thing, overcapacity throughout Europe*'. The potential unnecessary costs of this overcapacity have been estimated at up to 7.5 billion € per year in the period 2015-2030' (European Commission, 2016b).

However, avoiding these hindrances to the IEM is possible as far as the MS and respective TSOs involved are committed to a high degree of cooperation and coordination. First of all, the current barriers to XB participation should be identified and eliminate. Secondly, the specific design variables of the CRM implemented with regard to XB participation should be addressed.

III.3.1. **Current barriers to cross-border participation in CRMs**

In order to include generation from a neighbouring system in a capacity mechanism, the first main pillar required is a depth coordination and cooperation between TSO of the MS involved. For making it work, the TSO of the country implementing the mechanism should be confident on the neighbour contribution during a scarcity situation, if it has committed a physical capacity delivery. But actually there is a general mistrust, mainly because of two reasons (Paolo Matropietro, 2014) (EURELECTRIC, 2015a):

- The first one is linked to the accomplishment of the article 4(3) in the SoS Directive (2005/89/EC), which states that Member States are not allowed to discriminate between XB contracts and national contracts when taking safeguard measures or resolving congestions. There is a conflict of interests between national governments' desire to protect their own SoS at times of system stress and the pan-European approach to system adequacy. As a matter of fact, in most electricity systems there are regulations that specified interruptions of exports to other countries in case of threat to the national SoS. This might lead to the infringement of the directive in case of coincident scarcity situations at both sides of the XB interconnection.
- The second reason is related to the fully implementation of the Electricity Target Model, given that it would mean that the entire interconnector's capacity and flows would be allocated implicitly through equilibrium set by the comprehensive market coupling clearing algorithm. Therefore, in case of scarcity at a national level, electricity could be flowing out the country or the foreign capacity committed could not be supplied in the country. In some cases, the existence of XB interconnectors will lead to overinvestment in the country implementing the CRM.

The first barrier can be eliminated with a strong commitment between TSOs and by the modification of national network codes and operational procedures that hindrance the fulfilment of the Security of Supply Directive. The second hurdle is not that straightforward, but it can be removed by several approaches presented in the following subsection.

Other issue that complicates the XB participation is related to the fact that the foreign capacity contribution is provided partly by the foreign generators or demand response providers, and partly by interconnector allowing flow across borders. This makes necessary to take into account who (interconnector or neighbour capacity) is providing capacity during a scarcity situation. In other words, it may happen that during a stress situation the interconnector is congested, so even with oversupply in the neighbour country it not possible to alleviate the problem with its generation (or demand response). On the contrary, with capacity available in the interconnector, a coincident shortage situation in both countries may occur and then it would not be possible to transfer the capacity where needed. Moreover, as interconnector's revenues correspond to price differences between the interconnected markets, they are also affected by the "missing money problem". Hence, the design of an efficient solution for enabling cross border participation will involve an appropriate split of capacity remuneration between interconnector and foreign capacity to reflect the relative scarcity of each. Both interconnectors and foreign capacity providers but separately should be permitted to participate in the capacity remuneration scheme.

III.3.2. **Explicit cross-border participation**

This section is focused on the design issues that must be taken into account for allowing XB participation in individual capacity mechanism (EC, 2016b):

i. *Identifying the amount of foreign capacity that can participate, through establishing the contribution of potential interconnectors and foreign capacity participants.*

The calculation of the expected actual contribution (de-rating) is crucial for an effective XB participation. More attention should be taken into the interconnector availability calculation, given that too conservative results will lead to overcapacity with the consequent unnecessary cost. A proper cooperation and coordination between TSO and common rules becomes fundamental in this phase.

ii. *Designing the obligations and penalties that will apply to interconnector and foreign capacity participants.*

If a capacity provider have the obligation to physically deliver energy and faces penalties if its commitment is not fulfilled, it probably would lead to the internalization of this possible cost with the consequent distortion in the price of its system. In other words, it would not bid in its market at its variable cost but lower if it has risk of not being dispatch. Thus it would alter the merit order so as not to face penalties. Moreover, if owing to the shortage the price increases enough to reflect it, the flow would go to the zone with higher price and therefore the delivery obligation would have no impact as all generators would have the same incentive to supply electricity to the market with scarcity. For this two reason, a simple availability product is recommended.

Regarding the design of penalties, a provider that participates in more than one mechanism should face a penalty if it fails to supply the capacity committed in any of them. It means that, in case of concurrent scarcity condition, it has to choose where to supply and face one penalty, or even face both if it does not meet its obligations in any of the mechanisms. This double participation rises a concern on potential 'double-counting'[10] if not sufficient penalties are applied. In conclusion, multiple participation in different capacity mechanisms should be

[10] The concept 'double-counting' related to the situation in which a capacity provider is declared available simultaneously in more than a mechanism and there is scarcity in both systems. Therefore, it would mean that it will be twice remunerated.

permitted given that can efficiently deliver added value in specific situations, but as long as overlapping commitments are avoided and feasible solutions are properly identified (ENTSOe, 2015).

iii. *Identifying the counterparty for a XB capacity contract*

If it is the interconnector who participates in the mechanism, it is difficult to remunerate appropriately to foreign capacity providers without considering delivery obligations, so according to sector inquiry working document (EC, 2016b), it 'probably means that the most efficient solution would require foreign capacity to participate directly across border, rather than interconnectors participating'.

iv. *Determining the eligible foreign capacity providers*

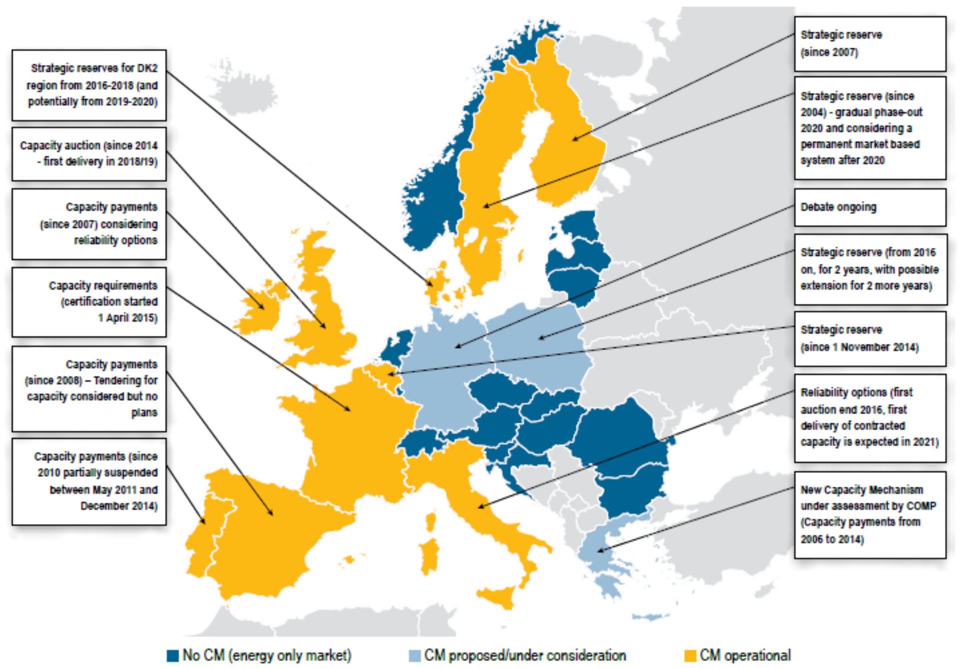
Limiting capacity commitments only to one market to avoid overlaps and thus overcompensation, leads to over investments[11]. For this reason, as stated also in point (ii), the participation of capacity providers in more than a mechanism for the same time period must be permitted.

After taking into account these four general designing matters when implementing a CRM that allows cross border participation, given that it escapes to the ultimate scope of this work, the consultation of the Staff working document of the sector inquiry (European Commission, 2016b) and the report on capacity mechanism of the energy directorate (DG ENER, COWI, 2013) are proposed for those looking for greater details on the matter.

III.4. INTERNATIONAL EXPERIENCES WITH CRM

In this section, an overview of different capacity remuneration schemes experiences is presented. The purpose is to extract conclusion out of those experiences and designs and have a guide for afterwards design alternatives for the Spanish case. Given that, as a Member State Spain must follow the European Commission guidelines on its implementation of a CRM, European experiences have been chosen. In the following Figure 9 a picture of the wide variety of CRM in place across MS is shown.

[11] For further understanding of the reasons of this over-procurement, a practical example can be consulted in annex 2 of the following reference (CNE, 2012b).



Source: NRAs (2015).

Note: In Germany, on 10 July 2015 Bundesnetzagentur informed the Agency that according to their assessment of a white paper[351] it is not clear whether the envisaged 'Capacity and Climate Reserves' (CCR) could be considered a capacity mechanism. In Poland: The mechanism in Poland envisaged for after 2016 includes generation units tendered by the TSO, which would definitely have been decommissioned by the end of 2015. This scheme has the characteristic of a strategic reserve capacity mechanism.

Figure 9. Capacity mechanisms in Europe (ACER, 2015).

As it is observed, there is not agreement neither in the selection of the type of CRM and if studied individually, nor in the design of the particular variables of each. Six of these countries have been selected in order to represent the different types of mechanisms introduced in previous section III.1. These are:

- Capacity market in UK
- De-central obligations in France.
- Reliability options in Italy
- Capacity payments in Portugal
- Strategic reserves in Germany
- Tenders for new capacity in Ireland

An in depth study of these mechanisms has been developed and its details can be consulted in Annex C. Nevertheless, in the following Table 9, a summary of the most relevant points and issues of these CRM are presented. Additionally, other international experiences are described in order to highlight some relevant design issues that reveal the importance of a sound design of this market intervention. By learning from the weaknesses and strengths of other CRM experiences, a sound design of the Spanish alternatives is intended to be done afterwards.

Table 9. Summary of international experiences with CRM.

	Central buyer model	De-central obligation	Reliability options	Capacity payments	Strategic Reserves	Tenders for new capacity
	UK	**FRANCE**	**ITALY**	**PORTUGAL**	**GERMANY**	**IRELAND**
Necessity	Increment in RES penetration and closure of thermal has led to under-investments in flexible generation.	Peak demand phenomenon leads to risk of shortfalls during winter cold spells.	Concerns on peak demand coverage are expected in the future.	Need of flexible backup generation. Low prices and missing money problem leads to no new investments incentives.	High RES penetration and phasing out of nuclear power plants have led to SoS concerns in the southern region.	Shortage of capacity expected so necessity of bringing rapidly new capacity.
Eligibility	Existing and new generators, DSR operators, storage operators and interconnectors	Demand response and storage and both new and existing projects. Interconnectors participation being assessed	Existing and new generators (if non-intermittent and programmable). Assessing the inclusion of DSR and interconnectors.	Investment incentive (II) to hydro power plants (new and repowering of existing). Availability incentive (AI) to thermal generation capacity. Both with a size requirement of minimum of 30 MW.	Mandatory part: all types of plants and storage providers with intention to close/ mothball and considered essential (located in the South). Voluntary part: foreign capacity (from the southern borders).	Opened to any new centrally dispatchable thermal plant, with a planned capacity greater than 50 MW. Foreign capacity permitted.
Allocation process	Central descending-clock, pay-as-clear auctions with a demand curve with price cap.	Tradable certificates market	Central descending-clock, pay-as-clear auctions with a demand curve.	Administrative procedure	Mandatory part: administrative procedure Voluntary part: tender procedure	Competitive bidding process
Remuneration	Premium at the auction clearing price (€/MW/year)	What they perceived from their capacity, linked to certificates price	Premium at the auction clearing price (€/MW/year).	Payment (€/MW/year) linked to the coverage index.	Payment (€/MW/year)	Payment (€/MW/year) in base of their availability.
Obligations	Deliver energy when a market warning is published.	Capacity providers: make their capacity available in specific hours announced day ahead. Suppliers: own production plants or curtailment system, or purchase capacity guarantees.	Submit offers in the day-ahead market for all their contracted capacity and rest into ancillary services and balancing markets. Return any positive difference between the spot and the strike price.	Obliged to provide energy whenever the TSO considers.	Not to participate in market and to be available whenever the resulting dispatch reveals congestions from north to south.	One way call option without physical delivery obligation but they have to return any positive difference between the spot price and the strike price.
Lead time	One four years ahead and other one year ahead.	Existing: 4-3 years New generation: 4 years DSR: 4 years to 2 months	From 4 years to less than 1 year.	-	Mandatory part: 1 year Voluntary part: 4.5 months	3 years
Contract duration	New built: 15 years. Refurbishing: 3 years. Existing and DSR: 1 year	A capacity guarantee is only valid for one year of delivery	From 3 to 1 year.	II: 10 years AI: operational lifetime	Network reserve - final closure 2 years Network reserve - preliminary closure up to 5 years	10 years
Main issues	Little new investments	Risk of vertical integration and of over or under-procurement	Risk of not bringing new capacity into the system	Regulatory uncertainty and low incentive led to little new investments	Less offers than demand of load.	-

III.5. ASSESSMENT OF THE VARIOUS TYPES OF CRM

The following Table 10 shows a summary of the characteristics of each type of mechanism that should be taken into account for properly choosing the most suitable alternative:

Table 10. Summary of assessment of the various types of CRM.

	APPROPIATENESS	ISSUES
Capacity payments	- Keep existing plants in the system - Foster new investments because it sends a fairly stable economic signal - Easy to address particular technologies	- Risk of discouraging new investment if too much old capacity is kept in the system - Risk of worsening the problem of non-eligible providers (windfall losses) - Difficulty in identifying the proper level of payment (overcompensation or under-incentives) - Real value of capacity not well identified - May increase the power of incumbents and therefore constitute a barrier for new entrances - No incentive for increasing efficiency or R&D
Strategic Reserves	- Keeping existing plants in operation - Back-up generation availability (firmness) - Solve locational scarcity problems - Solve transitional generation adequacy problem - Allows demand side participation and storage	- Does not solve the market failure that originate the need of CRM - It does not let price rise, so it aggravates the lack of proper investment signals - Possible regulatory risk .i.e. if the regulator dispatch the reserves more frequently for (over) protect consumers from high prices. - May accelerate exit from the market, if plants are incentivize to close to receive the remuneration. - Risk of market power - Risk of high emission levels form inefficient plants kept in the system - Incumbents may withhold capacity form the market to trigger the reserve.
Central buyer and Reliability Options	- Long term SoS issues - Transparent so prevents market power abuse concerns - The targeted capacity desired is procured - Competitive, so cost-effective - Able to address a systemic missing money problem - Compatible with XB participation - Variation of the capacity value and tend to zero when no more capacity is needed - (RO) Low distortion on market prices	- More complex and time-consuming mechanisms - Risk-averse authorities may set the reliability targets from the safe side (over procurement) - Eligibility criteria and product design require special attention - Need for a central determination of the volume and type of capacity needed - (RO) Special attention to the establishment and update of the strike price - (RO) Demand response is not incentivize because the maximum price perceived is the strike price
De-central Obligation	- Long term SoS issues - Able to address a systemic missing money problem - The value of the capacity can vary and tend to zero when no more capacity is needed - No need of a central determination of the volume and type of capacity needed (only the coverage index required) - Compatible with XB participation - Competitive, so cost-effective	- Eligibility criteria and product design require special attention - More difficult to address locational problems - More complex and time-consuming mechanisms - Importance of a well design penalty (for avoiding over or under procurement) - More uncertainty for suppliers who has to estimate their demand - New entrances may be hindered if there is too much market price uncertainty (longer contracts are more needed) - Incentive to VIU and hindrance to independent agents

CHAPTER IV: **The CRM in the Spanish power system**

In this chapter is focused on the specific experience of the Spanish electricity sector with CRM.

- Section 1 describes the specific experience of the Spanish electricity sector with CRM. It details the historical evolution of the schemes in place so as to address the security of supply concerns of the power sector, as well as a critical assessment of these mechanisms.
- In Section 2, the current situation of the Spanish power sector is described so as to release and assess which is the specific SoS issue that must be face when designing a new CRM.

IV.1. REVIEW OF THE REGULATORY FRAMEWORK FOR CRM

In Spain, there are nowadays two types of CRM: a capacity payment mechanism and an interruptibility scheme[12]. In turn, the capacity payment mechanism takes the form of two differentiated capacity products: one for incentivising availability of capacity (the availability incentive) and other for incentivising new investments (the investment incentive).

IV.1.1. **Capacity payments**

Since the liberalization of the Spanish electricity market in 1997, a CRM has been in place. An overview of the regulatory framework for CRM is presented in the following figure:

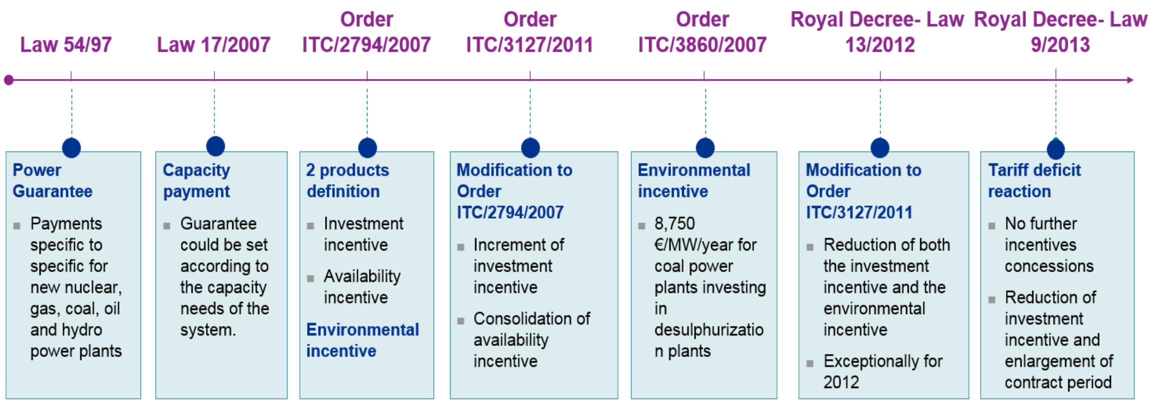


Figure 10. Regulatory overview of CRM in Spain.

Since the enactment of **Act 54/1997,** the Spanish electricity system design had to establish an economic signal for providing generators with an additional regulated income with the aim of incentivising investments and the efficient operation of generating plants, as well as for preventing the closure of plants considered necessary for the system.

[12] Between 2010 and 2014 there was also a mechanism consisting on a 'preferential dispatch for indigenous coal', however it was somewhat aimed at protecting the only national conventional resource existing in the territory rather than to provide adequacy to the system. For further information of the preferential dispatch for indigenous coal scheme see Royal Decree 134/2010

The so called "power guarantee"[13] evolved from a total volume of payments (specific for new nuclear, gas, coal, oil and hydro power plants) of 7.8 €/MWh of the system load in 1998, to 4.8 €/MWh from 2000 onwards (C.Batlle, 2007). For calculating this guarantee, the verified availability of each individual technology in the medium and long term was considered, and the price was set according to the "long-term needs". Later, **Law 17/2007**, also contemplated this scheme but under the name of "capacity payment" and the guarantee could be set according to the capacity needs of the system.

Later on, **Order ITC/2794/2007** stated that: given that the demand is inelastic and the network is not perfectly meshed, the spot price can be a signal insufficient to release the proper capacity to meet demand. In this vein, electricity supply was defined as a "public good" and so it needed an additional regulated remuneration (CNE, 2012b).

This Order acknowledged for the first time two different payments for the dimensions of adequacy and firmness, respectively:

- **Investment incentive:** it was an incentive for investments in capacity in the long term aimed at the construction and effective commissioning of new plants through payments that permit the recovery of the investment costs. The payment applied for the 10 first years from the start of operation of the plant. For installations commissioned after 1998 it was set at 20,000 €/MW/year. For installations with an installed capacity equal or greater than 50 MW and for installations commissioning after 2007 the remuneration (II) was linked to the 'coverage index' (CI) as follows:

$$If\ CI < 1.1\ \rightarrow II = 28{,}000\ €/MW/year$$

$$If\ 1.1\ \leq CI \rightarrow II = 193{,}000 - 150{,}000 \cdot IC$$

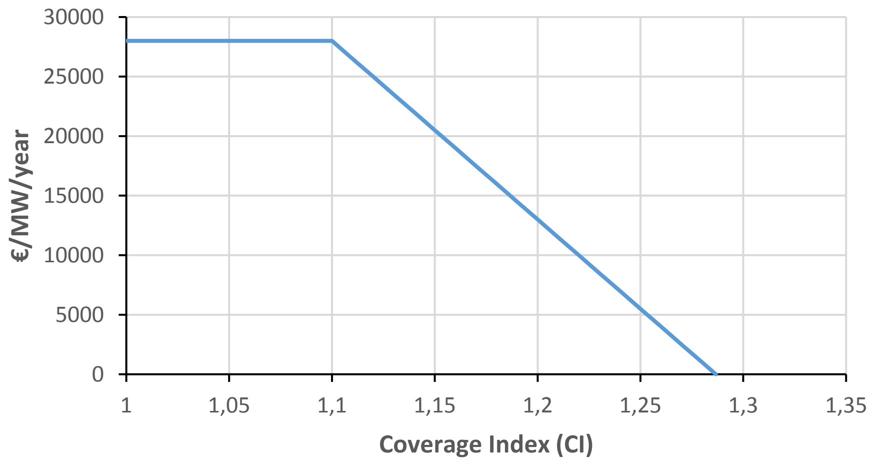


Figure 11. Investment incentive level as a function of the CI. Source: Own elaboration from (Gobierno de España, 2007a)

Order ITC/2794/2007 also introduced an incentive for environmental investments, targeted to coal plants that had invested in desulphurization plants. It was set at 8,750 €/MW/year with the **Order ITC/3860/2007.**

[13] In Spanish "*Garantia de potencia*".

- **Availability service:** it was conceived as a medium term incentive to some plants to be available during peak demand periods, as a complement to the balancing services of the system. The payment covered a period lower or equal to 1 year.

The availability service was completely developed in **Order ITC/3127/2011**, which also modified the investment incentive. This order supported the need for modifications of the previous scheme on this basis: (i) the reduction of demand due to the economic crisis and the penetration of new RES capacity to meet the 2020 targets were leading to a significant reduction of the load factor of some plants necessary to guarantee the SoS in the medium and long term and (ii) the interconnection with the main European markets was insufficient for exporting the exceeding production and thus increase these low load factors. The main modifications introduced by this Order were (CNE, 2012b):

- Investment incentive: the incentives for plants commissioned after 1998 was increased from 20,000 to 26,000 €/MW/year, because it was considered that the variation in the hours of production made the remuneration to these plants "not well adjusted". Incentives for environmental investments, additional to those devoted to desulphurization equipment in coal plants, were also considered in this service.
- Availability service: it was specified as an incentive to marginal technologies to make available all or part of their capacity to the System Operator, to prevent unavailability in peak hours because of insufficient remuneration. The service was conceived as a transitional measure for the period from 15th December of 2011 to 15th December of 2012.

The annual remuneration for the availability service of a unit *i* corresponding to the technology *j* followed the next formula:

$$RSD_{ij} = a \cdot ind_j \cdot PN_i$$

Where:

- a: Annual remuneration in €/MW. Set initially in 5,150 €/MW and later on would be set by the Ministry.
- ind_j: Indices that represent the availability of the technology *j* in unitary terms, based on historic availability values.
- PN_i: net power of the unit *i* in MW.

The eligible units for receiving this remuneration were thermal plants subject to the ordinary regime[14], hydro units with dam and pumping units. Installations subject to the special regime incentives and run-of-the river units were excluded. Participation in the mechanism was subject to administrative approval. The obligation of these installations consist in having available a proven an annual average capacity equivalent to its net power during the tariff periods 1 and 2, which are shown in Table 11.

[14] The differentiation between 'ordinary regime' and 'special regime' was first introduce by the Law 54/1997 of the electric sector. With the first group, those plants with more than 50 MW are referred.

Table 11. Time intervals of each tariff period according to Order IT/2794/2007. Source: Own elaboration.

Zone		Mainland		Canary and Balearic Island		Ceuta and Melilla	
Days type		Type A[15]	Type A1[16]	Type A	Type A1	Type A	Type A1
Period	1	From 10 to 13 h. From 18 to 21h.	From 11to 19 h.	From 11 to 14 h. From 18 to 21h	From 11to 19 h.	From 12 to 15 h. From 20 to 23h.	From 11to 19 h.
	2	From 8 to 10 h. From 13 to 18h. From 21 to 24 h.	From 8 to 11 h. From 19 to 24 h.	From 8 to 11 h. From 14 to 18h. From 21 to 24 h.	From 8 to 11 h. From 19 to 24 h.	From 8 to 12 h. From 15 to 20h. From 23 to 24 h.	From 8 to 11 h. From 19 to 24 h.

Moreover, planned outages had to be approved by the SO as far as they are notified at least 20 days in advanced and they could never exceed the 33% of the hours of these periods.

The penalties applied if the obligations were not met are:

- Annual incentive reduction in an amount proportional to the number of hours not available in tariff periods 1 and 2 once discounted the planned outages, up to a maximum of 75% of the incentive.
- Suspension of the payments in subsequent periods if the proven annual average capacity was lower than 60% during the tariff periods 1 and 2 once discounted the planned outages.

Afterwards, based on the low demand and the low risk of capacity deficit, the **Royal Decree-Law 13/2012** introduced again modifications to the investment incentive exceptionally for the year 2012. It established a reduction of the remuneration to 23,400 €/MW/year and the environmental investment incentive to 7,875 €/MW/year.

Order IET/221/2013, of 14th February, set forth the application of availability incentive envisaged in the Order ITC/3127/2011, from the 1st of January of 2013.

Even further reductions were set forth with the **Royal Decree-Law 9/2013,** of adoption of urgent measures for guaranteeing the financial stability of the electricity system. For facilities that had already right to remuneration, the investment incentive was cut down to 10,000 €/MW/year. This reduction came along with an enlargement of the period of payment to the double of the remaining days from the 10 stablished in the annex III of the Order ITC/2794/2007. The period in days was calculated as follows:

$$Period\ of\ payment = (EndDate - StartDate) \cdot 2$$

Where $EndDate$ was the date of ending of the right to receive remuneration and $StartDate$ was the entry into force of this RDL.

Those installations that, by the entry into force of this RDL, were not accepted in the mechanism lost the right to perceive it unless they had a commissioning certificate for start operation before the 1st of January of 2016. In this latter case, they had the right to perceive the 10,000 €/MW/ year during 20 years.

[15] Type A refers to days: From Monday to Friday non holiday of peak season with morning and evening peak.
[16] Type A1 refers to days: From Monday to Friday non holiday of peak season with morning peak

On the other hand, the availability incentive as defined in the Order ITC/3127/2011, was set forth for 2014 in **Order IET/107/2014**, for 2015 in **Order IET/2444/2014** and for 2016 in **Order IET/2735/2015**.

Table 12 and Table 13 show the resulting evolution of the regulated payments introduced by each piece of regulation:

Table 12. Investment incentive and environmental incentive remuneration evolution. Source: Own elaboration from CNE and BOE.

INVESTMENT INCENTIVE (€/MW/year)	**Order ITC/2794/2007 and ITC/3860/2007**	**Order ITC/3127/2011**	**Royal Decree-Law 13/2012**	**Royal Decree-Law 9/2013**
Capacity	20,000	26,000	23,400	10,000*
Environmental	8,750	8,750	7,875	8,750

* During 20 year

Table 13. Availability incentives remuneration evolution. Source: Own elaboration from CNE and BOE.

AVAILABILITY INCENTIVE (€/MW/year)	**Order ITC/3127/2011***
CCGTs	4,697
Coal plants	4,702
Fuel-oil plants	4,517
Hydro plant with dam and pumping units	1,221
Rest of plants	0

* set forth initially for the year 2012 and set forth for 2013-2016 with Order IET/221/2013, Order IET/107/2014, Order IET/2444/2014 and Order IET/2735/2015 respectively.

Figure 12 shows the evolution of the capacity payment component along with the average annual spot price. Until 2011 the price for consumers owing to capacity payments increased, it remain stable between the year 2011 and 2012, for then decrease influenced by the measures of RDL 9/2013.

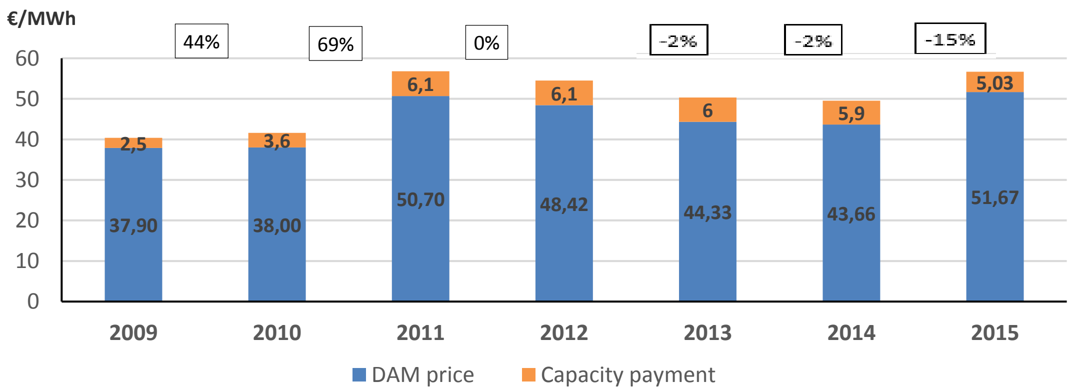


Figure 12. Evolution of the capacity payment component and the DAM component on the final price for the period 2009-2015. Source: Own elaboration from 2009-2015 REE electricity system reports.

IV.1.1.1. *Summary of the current mechanism*

Table 14. Main characteristics of the capacity payments mechanisms in 2016.

	Investment incentive	Availability incentive	Environmental incentive
Eligibility	Nuclear, gas, coal, hydro and oil entering into service before 1 January 2016. Installed capacity >50MW.	Thermal generation (except nuclear) and hydro (with storage)	Coal plants- to install a Sulphur dioxide filter
Allocation process	Administrative	Administrative	Administrative
Incentive	10,000 €/MW/year	(See Table 13)	8,750 €/MW/year
Obligations	Build and operate an eligible power plant with no additional performance requirements.	Prove that 90% of the capacity receiving availability payments was available in peak periods.	Effective installation of the plant.
Penalties	-	Lose up to 75% of payments and even exclusion for future years.	-
Contract duration	20 years	1 year	10 years

IV.1.2. **Interruptibility scheme**

The interruptibility service, as stablished by the **Order ITC/2370/2007**, consists on providers of this service (mainly large-scale industry) reducing its active power consumption to the value required by the system operator. According to REE, it is '*a demand-side management tool aimed at providing flexible and rapid response to the needs of the electricity system operator in situations of imbalance between generation and demand*'.

There were several types of power reduction (from 1 to 5) depending on the pre-notification of the service requirement by REE and the maximum duration of the interruption. The duration of the interruption was composed by one or more periods of one-hour of minimum duration each and at least one-hour lapse between them.

The remuneration was an annual payment calculated as follows:

$$RSI = DI \cdot FE$$

Where DI is a discount factor and FE is the price of the corresponding equivalent annual energy turnover[17]. The individual remuneration had a maximum of 20€ per MWh consumed.

In case of unfulfilment of the obligation, the penalization applied was proportional to the remuneration received the year of the breach or even the rescission of the contract.

Several changes applied to the mechanism with the RDL 13/2012 and the Order IET/2804/2012. The first, added a random testing of demand curtailments and set a maximum annual remuneration at 505 million € and the order gave priority to those with higher curtailment capacity and increased the individual remuneration of capacity providers. However, the most relevant change was introduced with the entry into force of **Order IET/2013/2013**., which established that the interruptible demand service shall be allocated through a competitive auction process managed by REE.

Other change introduced was the differentiation of two interruptible capacity products auctioned separately: one consisting of reductions in consumption of 5 MW and another of 90 MW. The allocation procedure, which will be held once per year and four months in advance, is an iterative descending clock auction, i.e. starting from an initial price, the amount goes down in each round at a previously established price (step). In this way, the service is awarded to the last competitor remaining who is willing to offer the service at the lowest price. The requirements for eligibility and the penalizations for unfulfilment of the obligations were also redefined.

Other changes introduced were: the types of power reduction (now three types), the pre-notification of the service requirement, the maximum duration of the interruption (one hour) and the maximum number of hour of interruption (will be 240 h/year (40 hours/month) for the 5 MW product and 360 h/year (60 hours/month) for the 90 MW product).

Later on, Order IET/2013/2013, was amended by **Order IET/346/2014**. It modified the remuneration of the service for each provider, which was set as the sum of:

- Fixed term: associated to its capacity availability, calculated by multiplying the allocated capacity in the auction by its resulting price.

[17] The calculation of these terms can be consulted in the article 6 of the Order ITC/2370/2007.

- Variable term: associated to the effective provision of the service, i.e. to interrupt the demand when notified by REE.

In case of breach on the obligations and requirements of the service penalties were applied. If it was the first unfulfilment, the capacity provider:

- Had to pay a penalty stablished in base of remuneration perceived for the energy consumed and so not interrupted until a maximum of 120 % of that remuneration.
- Do not receive the variable remuneration acknowledged.

In case of a second unfulfilment in the same period, the provider will be excluded from the service, it will lose the remuneration for that period and it will have to return what was already perceived. For more details about the calculation of the penalties, the article 11 of the Order IET/2013/2013 can be consulted.

Moreover, this Order stated that the cost of the service will be assumed by both generating units and demand.

Later on, the **Order IET/1752/2014**, modified the two previous orders to redefine some procedures.

IV.1.2.1. *Summary of the current mechanism*

Table 15. Main characteristics of the current interruptibility scheme service in 2016.

Eligibility	Demand response >5MW or >90MW (two auctions)
Allocation process	2 auctions (one for each product)
Remuneration	Fix term + Variable term
Obligations	Effective reduction of demand when required.
Penalties	Pay a percentage of the fixed term up to 120% of it and lose the right to perceive the variable term. Exclusion of the mechanism for recurrent unfulfilment.
Lead time	~ 4 months
Contract duration	1 year
Capacity contracted (for 2016)	2890 MW
Estimated cost for 2016	503 million €

IV.1.3. **Design issues - Weaknesses of the mechanisms**

IV.1.3.1. *Capacity payments*

<u>Static level of remuneration</u>

In Spain, the reliability standard is set at a 10% of coverage index, hence, according to this value, there is overcapacity since early 2008. This problem of overinvestments, with the consequent high costs for consumers, could have been avoided if the capacity requirements would have been linked somewhat to the actual needs of the system as provided by Order ITC/2794/2007. This means that the remuneration should have decreased and eventually be zero when the coverage index had been exceeded so as to avoid that the capacity mechanism send misleading signals for investment

However, that methodology was never applied and, instead of adapting this standard in order to provide the right economic signals, the level of remuneration was administratively set and the payment maintained (and increased for some periods) even in times of overcapacity and current coverage index is 1.37.

Figure 13 shows the evolution of the coverage index along with the evolution of the remuneration scheme that applied for each period.

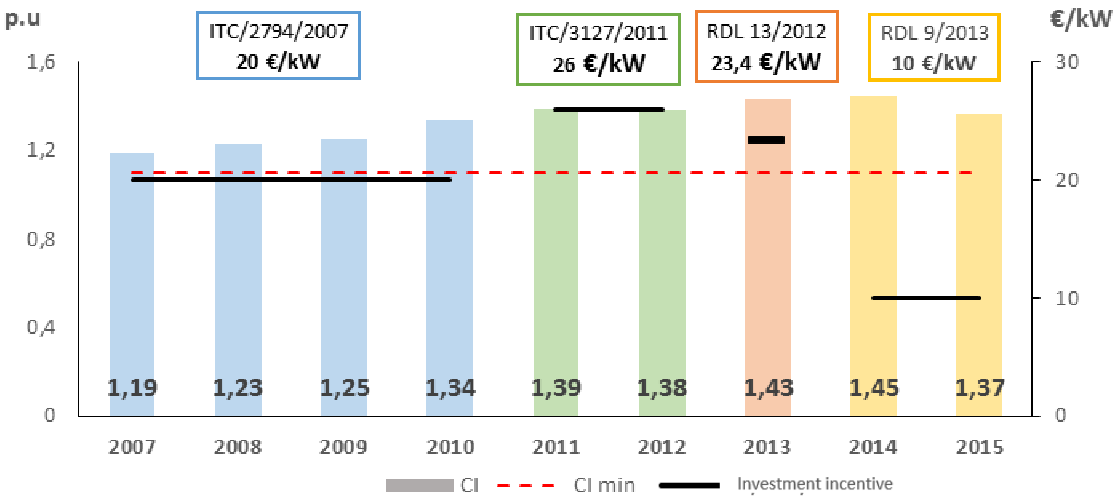


Figure 13. Evolution of the CI along with the investment incentive from 2007 to 2015. Source: Own elaboration from (REE, 2015b).

As stated by (IEA, 2015), the current capacity payment system is '*relatively expensive and not targeted at the power plants needed to ensure generation adequacy in a least cost manner*'. IEA bases this affirmation on the fact that the 27 GW of CCGT fleet which is receiving this payments is idled. According to (REE, 2015b) figures, the load factor of CCGT is of 12.9%. This costs could have been avoided if from the beginning the remuneration of the capacity entering the system would have been linked to the real value of that capacity at that very moment. In this way, certainly less capacity would have entered the system and therefore, the cost of the actual overcapacity would be less significant.

Regulatory changes

The initial 'power guarantee' mechanism suffered several changes of the remuneration (from 7.8 €/MWh in 1998 to 4.8 from the year 2000 on). This regulatory uncertainty undermined signals for investment up to the point of sending the coverage index below the 1.1 aimed as Figure 14 shows. Market agents believe that this mechanism prevented some plants from closure more than fostering new entrances (C.Batlle, 2007). Additionally, given the short duration of the availability incentive contract and the numerous changes in the remunerations of the investments incentive, the mechanism could be seen as a measure for avoiding plants from exiting the system more than fostering new investments (EC, 2016b). Moreover, as it has been introduced, the investment incentive, the availability incentive and the interruptibility scheme have been rather unstable until nowadays.

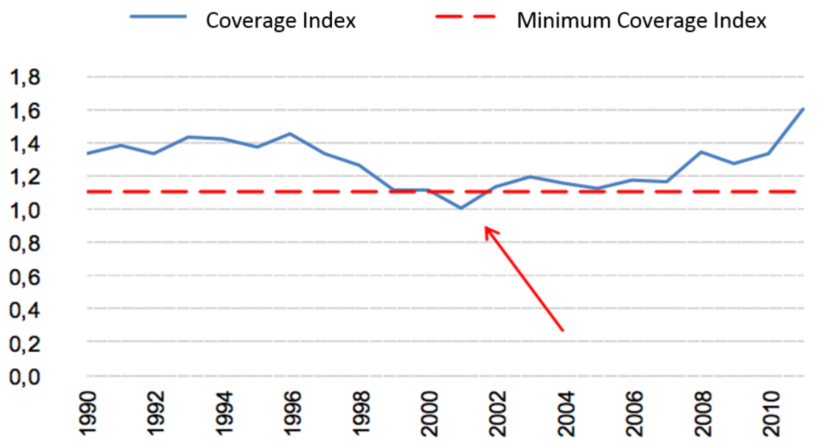


Figure 14. Evolution of the Coverage Index 1190-2010. Source: (CNE, 2012b)

<u>Selectivity leads to a snowball effect</u>

As introduced before, too selective eligibility criteria may lead to a 'snowball effect', and this is the case of the Spanish targeted capacity payment mechanisms. As declared in the sector inquiry '. *As early as in 1997 Spanish power plants started receiving targeted capacity remuneration. This however did not appear sufficient to address the generation adequacy problems, since in 2007 the scheme was complemented by an interruptibility scheme and later still, in 2010, by a preferential dispatch scheme for indigenous sources (coal)*' (EC, 2016b).

<u>Administrative allocation processes do not reveal the real value of capacity</u>

The current level of incentives is not enough for the capacity providers to recover their fixed operation cost (see Figure 17 and Figure 18). This means that the administrative procedure for setting the payment fails at solving the missing money problem of most of the CCGT and many of them would be willing to mothball if allowed. In fact, this possibility was contemplated by the Regulator (CNE, 2013a), but it has not yet been approved. As stated in the sector inquiry, setting the level of remuneration through a competitive allocation procedure is more likely to reveal the real value of capacity.

<u>Not proper definition of the capacity product</u>

The flawed design of the penalties that applied under the capacity guarantee scheme, in place in Spain till 2007, led generators to untrustworthy declare its availability and/or to bid to high in order not be dispatched without risk of being penalized (C.Batlle, 2007). Likewise, the penalty that applied was too low (in proportion to the annual capacity payment received) to represent an incentive for been available. This problem was addressed with the differentiation of the two products introduced by the Order ITC/2794/2007.

Other design characteristic of the capacity guarantee was the methodology used to calculate the firm capacity that each plant was able to provide, procedure described as 'extremely crude and arguable' by (C.Batlle, 2007). It basically consisted on multiplying the average availability rate times a capacity value, which was the installed capacity for thermal plants and for hydro units the energy produced in an average year. The latter were not discriminated depending on the reservoir size or even the existence of it and it would not allow to give more weigh to less polluting units.

Regarding the obligations of the capacity providers, two questionable requirements were in place, namely the minimum requirement of 480 hours that the units had to produce per year in order to receive the remuneration and the minimum fuel reserves that had to have. The first one, might interfere in the dispatch if these plants would have bid lower in order to fulfil the requirement. The second obligation would have required deep supervision, owing to the fact that a secondary use of the fuel could be more economically attractive than keeping it stored.

IV.1.3.2. *Interruptibility scheme*

Capacity requirement calculation

In Spain, respondents to the sector inquiry stated that the target of interruptible capacity to be procured is overestimated. As it occurs in the case of the investment incentive, this impact can be related to the fact that the capacity demanded is not linked to the achievement of the 1.1 coverage index. It basically means that the reliability standard does not fulfil its main function, namely to ensure an appropriate level of capacity (EC, 2016b).

Non-competitive allocation process

As explained, the initial **interruptibility scheme** was based on fixed payments set administratively until 2014. During that period, the cost of remunerating 2,000 MW of interruptible capacity mechanism is shown in next Figure 15:

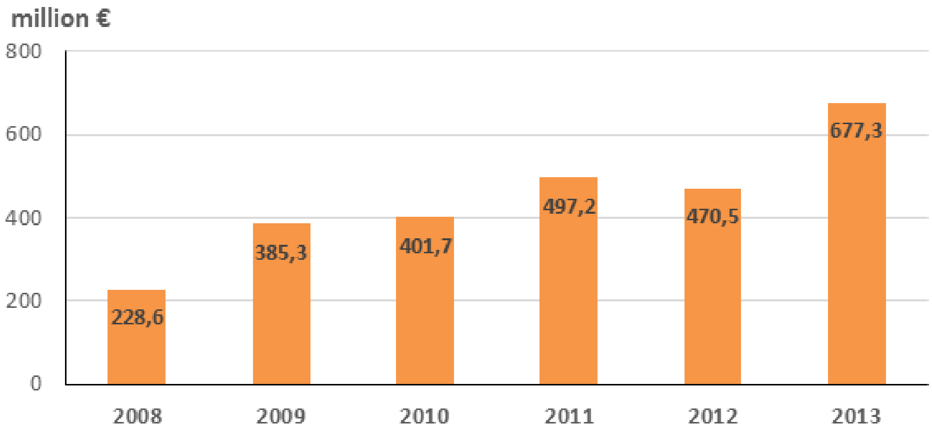


Figure 15. Cost of the interruptibility service in the period 2008-2013. Source: (CNE, 2013b), (CNMC, 2014).

In 2014, with the introduction of the competitive allocation process, the first auction that was celebrated for allocating 2,000 MW of interruptible demand for the year 2015 with a maximum annual budget of 505 million €, had a cost of 353 million €, far lower than the disbursements of the previous scheme. However, an extraordinary auction took place immediately after for allocating 1,020 MW and eventually the total cost of the scheme reached very similar values to the prior ones and therefore very close to the maximum budget available for the mechanism, i.e. 508 million € (EC, 2016b) (REE, 2015a). In the second auction taken place for allocating 3000 MW of interruptible demand, 2890 MW were allocated for 503 million €. It represented an increment in the cost of the service of 3.47% (from 168,212 €/MW to 174,048 €/MW) (REE, 2015a).

The mechanism has been hardly criticized for being considered as an indirect subsidy to energy intensive industries. Opinion supported by the fact that the mechanism had never been used since 2009 (EC, 2016b).

To sum up, it can be concluded that non-competitive allocation process do not reveal the right price of capacity and an excessive disbursement may take place. Nevertheless, even in competitive mechanism, if the maximum budget is too high to foster competition among the participants, risk of market power abuse arises and agents tend to bid very close to the maximum annual budget (i.e. the maximum budget was 505 million € and contracts for 503 million € were signed) (EC, 2016b).

Testing of the availability

Some concerns arise, motivated by the issue of the RDL 13/2012, regarding the testing of the availability of the plants carried out by the system operator to ensure that contracted resources are actually capable of meeting their obligations (even in years when there are no periods where obligations apply).In order to check the effective functioning of the interruptibility scheme, it had to be randomly applied every year in a 1% of the hours with the highest foreseen demand. In this vein, demand response providers claimed that this requirement implied a potential entry barrier to the mechanism, given that the impact of testing demand reduction implied the effective curtailment of the load (European Commission, 2016b).

IV.2. ASSESSMENT OF THE CURRENT SITUATION AND FUTURE STEPS NEEDED

Capacity margins in the Spanish electricity system are currently in safe levels. However, this situation may no longer hold in the medium to long term, as there is considerable uncertainty about the evolution of the generation fleet and the demand.

As can be overseen, the future of the Spanish electricity sector will vary widely depending on the upcoming events and so will the SoS to be faced.

IV.2.1. Generation mix evolution

Nuclear

Regarding the generation fleet, the future evolution of the mix is potentially dependent on political decisions. This is especially critical when analysis the future of the 7,573 MW installed of Nuclear Power plants capacity, which represented the 21.8% of the Spanish electricity production in 2015 (REE, 2015b). Nuclear power plants will reach the end of their 40-year design life in the 2020s. At this point, a political decision will declare whether their life will be extended beyond 40 years or, on the contrary, they will be closed. The events at European level also could guide the uncertain evolution of nuclear capacity. Current trends in other countries as well as certain political parties seems to be moving for a nuclear phase-out as it is the case of Germany.

Coal

With regard to coal power plants, a rise in carbon prices will predictably jeopardize the economic viability of this technology leading to their shut-down. Additionally, domestic coal power plants have been reliant on public support justified by SoS reasons, i.e. the preferential dispatch for indigenous coal which is no longer in force since 2014.

Directive 2010/75/CE of Industrial Emissions (DEI), which came into force in 1st January 2016, defines more tight limits of emissions than the previous National Plan of Emissions Reduction. Some plant have been subjected to a National Transitory Plan (PNT) so as to be permitted the non-compliance of the emissions limit values (VLE) on NOx, SO_2 and particulate until 2020 by making the necessary investment to fulfil the limits after 30th June 2020. The installations that decide not to invest in reducing pollutants will operate 17,500 hours from 1st January 2016 until closure in 31 December 2023 (CNE, 2012b).

RES and CCGT

One of more relevant concerns on the Spanish SoS is related to a switch to a more renewable generation mix. The 20-20-20 European objectives of third package for the year 2020 are not been complied. Furthermore, after the Paris Climate Conference (COP21) of December 2015, these objectives have been consolidated for 2020 and tighten for 2030 as Figure 16 shows:

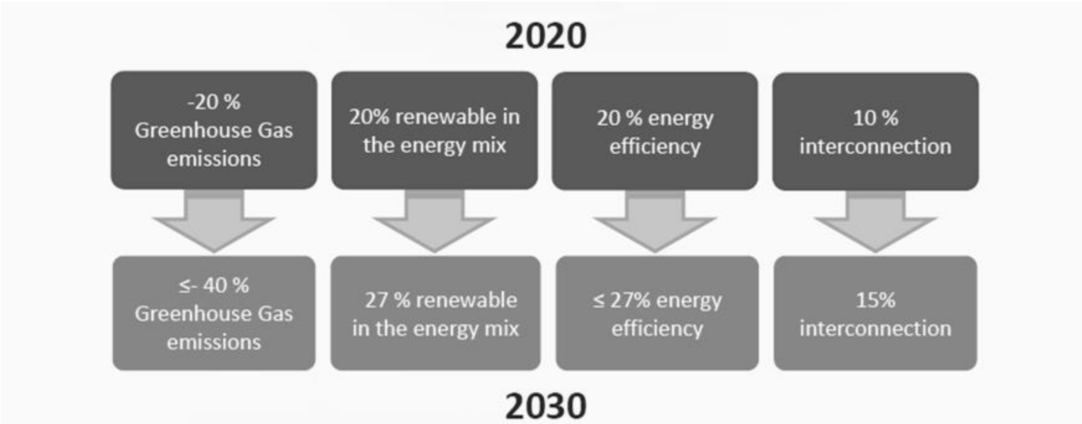


Figure 16. European Climate Change Policy objectives. Source: REE lecture at MEPI.

For achieving this objective and thus, being able to face the SoS concerns that the intermittency and weather dependency RES will imply for the electric power system, higher levels of flexible back-up generation will be needed. It has been estimated that up to 30 GW of RES generation would be needed in order to reach the 2030 objectives (Deloitte, 2016), (ENTSOe, 2014). This would mean a considerable amount of back-up generation needed and that might be larger if the nuclear power plants are phased out.

However, a combined scenario of low market prices and low load factors have not been and would not be attractive for investors. Since year 2009, CCGT power plants have not been able to recover all their total fixed costs (see Figure 17). Moreover, as estimated by CNE, in the year 2012 up to an 80% of the CCGT capacity would not have been able to recover their operational fixed costs as Figure 18 shows.

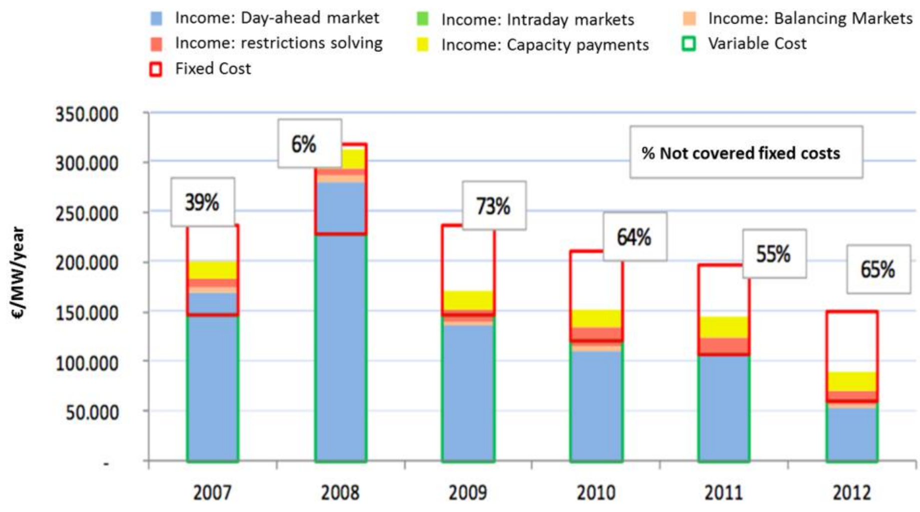


Figure 17. Evolution of the non-recovered total fixed costs of the Spanish CCGT plants. Source: (CNE, 2012b).

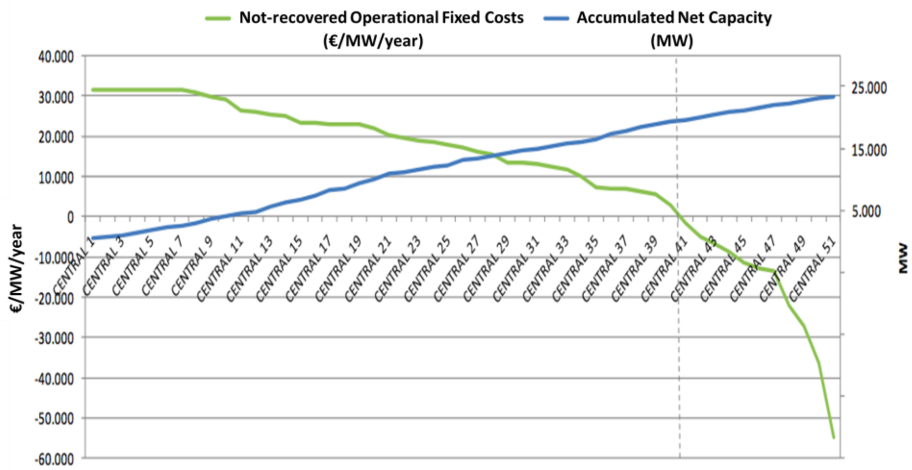


Figure 18. Estimation of the non-recovered fixed operational costs of the Spanish CCGT plants (CNE, 2012b)

IV.2.2. **Future security of supply concerns**

As explained in this section, from the beginning of the liberalization of the electricity market, Spain has counted on CRM as a tool for ensuring a secure energy supply. As a matter of fact, the Spanish CRM have simultaneously consisted of investment incentive, availability incentive, environmental incentive, interruptibility service and capacity payment for domestic coal units.

However, SoS continued to be a concern and so did the flawed design of the successive CRM. In this vein, the last consideration of changing the Spanish capacity remuneration scheme was introduced by an additional disposition to the Order ITC/3127/2011. As it was stablished in this order, in December 2012 the CNE issued a proposal of a new CRM as a result of a public consultation (CNE, 2012b). Specifically, the CNE justified the necessity of a CRM based on the following:

- Price cap does not reflect scarcity prices.
- Low demand elasticity to respond to high prices.

- High RES participation that may lead to deficit of energy in the medium term when not available.
- Risk of deficit of reserve margin in the long term due to lack of investment.
- Low interconnection capacity with Europe.

According to the Order ITC/3127/2011, the new CRM design should have been approved by the Ministry. Nevertheless, no further progress has been made in its development and implementation ever since.

Despite, as it has been said, nowadays the CI is in safe levels, 1.37 in 2015 (REE, 2015b), in the event of high annual increase of demand (up to 2.3% according to a scenario of (MINETUR, 2015)) and the high rate of penetration needed so as to comply with the 2030 targets, SoS concerns arise. Moreover, the 'missing money problem' is still a reason for plants to be willing to mothball or close and low prices due to high RES shares do not send right economic signal for expecting new investment in flexible generation capacity.

One option, that might alleviate this SoS concerned could be to invest in increasing interconnection capacity with Europe. Even if the three Projects of Common Interest (PCIs) contemplated under the 2016 Ten Year Network Development Plan (TYNDP) actually materialized, Spain is expected to remain under the European Union objective of the 10 % (ENTSOe, 2014). As Figure 19 illustrates, a maximum of an 8% of its demand could be covered with interconnectors.

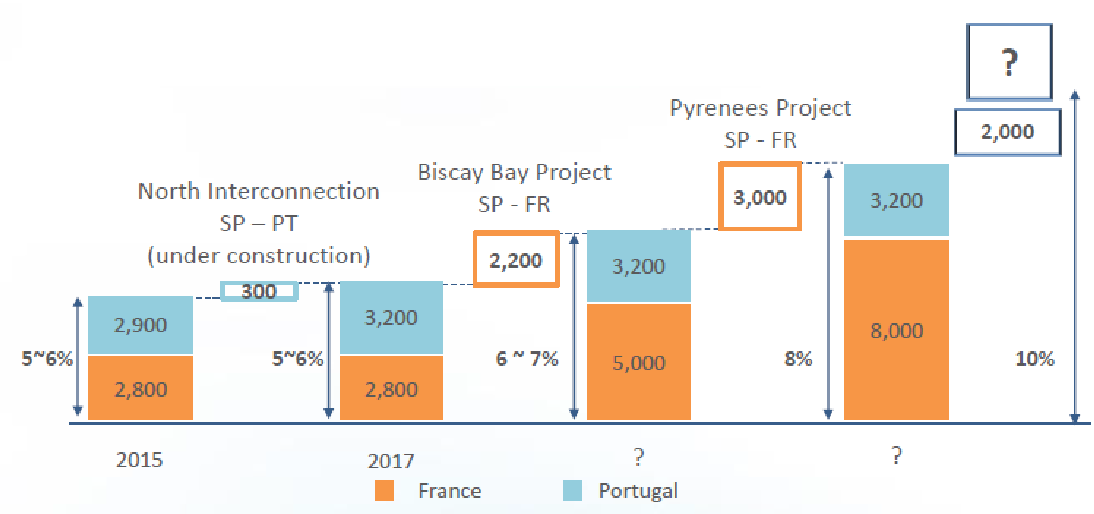


Figure 19. Evolution of the interconnection capacity with the construction of PCI (REE, 2015).

IV.2.3. **European assessment of the Spanish CRMs**

The last event that spurred the need of redesigning the Spanish CRM was the publication of the "Interim Report of the Sector Inquiry on Capacity Mechanism" (European Commission, 2016a), that was a result of the inquiry launched by the European Commission (EC) launched in April 2015. The design and performance of current Spanish CRM was put into question (an even hardly criticized).

As stated in the report of the EC, the main objective of the inquiry is to extract conclusions about whether the different CRM already implemented (or planned to be implemented) are able to ensure capacity adequacy and firmness without distorting competition or trade in the IEM. And according to the EC, Spanish mechanism is not following these guidelines.

Along with EC guidance on public interventions (European Commission, 2013) , other European authorities and regulators have issued a series of reports that provide guidance when assessing the need for interventions to ensure generation adequacy and in choosing the appropriate method or design of intervention e.g. (European Commission, 2014a) (European Commission, 2016a) (DG ENER, COWI, 2013) (ENTSOe, 2015), (ACER, 2013), (ENTSOe, 2015) (EURELECTRIC, 2015b) and (CEER, 2013). Spain, support by these experts, has the tools to face any SoS of concern that may arise with the most suitable interventions as possible. It will be able to choose the intervention which least distorts cross border trade and the effective functioning of the IEM, as the Electricity Security of Supply Directive states.

CHAPTER V: Presentation of the problem

In this chapter, the problem we are facing is presented. It is divided in three sections:

- In section 1, it will be specified which are the needs of the system, this is what the CRM has to address. Due to the uncertainty that we are facing nowadays at a national and European level, **3 scenarios** have been considered.

  This scenarios will be studied by means of an Iberian wholesale electricity market model developed by the KPMG Economics & Regulation Practice, which has been adapted in fit with the objectives of this master's thesis with the assessment of CRM. An explanation of the details of this model are explained in annex F. In this section the model will give us information about which will be the need of the system in the period 2020-2030.

- In section 2, 2 **alternative design** will be selected and design so as to perfectly solve the SoS detected in section 1. For the selection and design of the CRM alternatives, the criteria that has been considered is:
  i. Conclusions obtained from the **state of the art** study developed
  ii. **EC guidelines** (EC, 2003) (EC, 2013a)
  iii. **CNMC proposal** of CRM (CNE, 2012b).

- Section 3, presents the **method followed** so as to simulate the alternative designs by means of the KPMG market model. It will focused on the necessity of reaching the CI stablished by REE and the strategy that agents will followed once they are awarded with one or another CRM contract.

Afterwards, in CHAPTER VI: these alternatives will be assessed so as to evaluate if they are able to address the SoS problem and to what extent and under which circumstances they are more appropriate.

V.1. EVALUATING THE NEED FOR CRM IN SPAIN IN THE MEDIUM TO LONG TERM: DEFINITION OF SCENARIOS

The reliability standard used by the Spanish TSO is the so called Coverage Index (CI) and is calculated as:

$$CI = \frac{Total\ firm\ capacity\ (MW)}{Annual\ Peak\ demand\ (MW)}$$

Where:

$$Total\ firm\ capacity_y = \sum_i Net\ Capacity_{i,y} \cdot Firmness\ Coefficient_i$$

Where i refers to the type of technology considered and y the year of study.

The criterion of REE is to consider that the minimum level of the CI to guarantee SoS is 1.1, and therefore it will be considered as adequate and that SoS level will be the objective of the CRM implemented.

The firmness coefficient is established taking into account the contribution to cover the system peak demand according to historical values (Gobierno de España, 2014). They are given by the Government and are shown in Table 16:

Table 16. Firmness coefficients used to calculate the firm capacity of each technology. Source: (Gobierno de España, 2007b)

Technology	Firmness Coefficient
National coal	95%
Imported coal	96%
Nuclear	95%
CCGT	94%
Hydro: dam and mix pumping	45%
Hydro: pure pumping	90%
Mini-hydro	30%
Wind	9%
Thermal solar	30%
Solar PV	0%
Cogeneration	70%
Biomass and biogas	50%
Waste	50%

The *Annual Peak demand* has been calculated as the maximum annual demand during a year, discounting the interruptible demand if any.

The objective of the CRM design will be to attract investment in new CCGT capacity so as to comply with the minimum 1.1 of CI.

This requirement will be assessed in three scenarios which differ in their generation mix, due to alternative paths of thermal plants shut-down and renewable penetration levels.

The starting point of the study will consist on an initial evaluation of the evolution of the CI under the assumption that no CRM is in place: both the availability incentive and the interruptibility scheme will be considered as phased-out. On this basis, we will have a reference scenario with no CRM which will be tested against the outcome of the incorporation of the proposed CRM design so as to assess their impact in terms of several relevant variables.

In the following section V.1.1. Common assumptions taken for each scenarios are introduced, whereas in section V.1.2. The three scenarios of study are justified and described.

V.1.1. Common assumptions for the three scenarios

a. Demand increases by 2.3% each year until 2030

According to the transport grid planning for 2015-2020 (MINETUR, 2015), the demand is expected to grow with a rate between 1.7% in the low scenario and 2.3% in the high scenario.

In order to represent the most unfavourable situation, the values from the high scenario have been chosen as a common input value for the three scenarios i.e. growth rate of 2.3%

per year However, some sensibilities will be done a posteriori so as to evaluate the behaviour of the CRM if the growth rate varies.

b. CO2 and commodity prices

For the price of the natural gas, imported coal and carbon the assumptions of the World Energy Outlook 2014 have been used (IEA, 2014). The future prices for 2020 and 2030 for the so-called low oil scenario have been converted to euros of 2014 and the results are shown in Table 17.

Table 17. Prices of commodities and CO2 in the period of study. Source: (IEA, 2014).

		2020	2022	2024	2026	2028	2030
Imported coal	[€/ton]	66,24	66,99	67,75	68,50	69,25	70,00
National coal(*)	[€/ton]	75,00	75,00	75,00	75,00	75,00	75,00
Gas	[€/MWh]	15,14	17,71	20,27	22,84	25,41	27,97
CO2	[€/ton]	22,00	23,00	24,00	25,00	26,00	27,00

(*) National coal prices have been estimated as an average of the prices published in the Ministry of Energy Resolution of 2014 relative to the "security of supply" mechanism (Gobierno de España, 2015).

c. RES installed capacity in 2020

With regard to the RES generation fleet installed at the beginning of 2020, also the prevision of (MINETUR, 2015) has been taken. These values are shown in Table 18:

Table 18. RES installed capacity in 2020. Source: (MINETUR, 2015).

Technology	Capacity installed [MW]
Wind	27,650
Thermal Solar	2,300
PV solar	5,790
Cogeneration	5,348
Mini-hydro	2,309
Biogas and Biomass	1,254
Waste	1,750

d. Hydro and pumping installed capacity and evolution 2020-2030

With regard to the hydro power plants the capacity installed considered stable along the period for study and equal to the capacity registered at April 2016. The values of capacity installed of pumping units, have been taken from (MINETUR, 2015), where it is also stated that the installed capacity will remain constant along the decade.

Table 19. Hydro and pumping units capacity in 2020. Source: (MINETUR, 2015).

Technology	Capacity installed [MW]
Hydro plants	14,753
Pure pumping	3,800
Mixed pumping	2,800

e. Installed CCGT evolution

The installed capacity of CCGT will be steady given that the entrant capacity will be included in a differentiated group. However, both existing and new entrances will be considered identical technologies in terms of variable costs, fuel costs, emission factor, etc. The relevant technical and economic data is provided in Table 20.

Table 20. Technical and economic data of CCGT fleet

Unitary Gross capacity	400	[MW]
Unitary Net Capacity	380	[MW]
Performance	50.8	[%]
CO2 emission factor	0.36	[tonCO2/MWh]
Operational Fix Cost	31,300	[€/MW]
Investment Cost	803	[€/kW]
Amortization	15	Year
TIR	8.5	%

Considering the natural gas price and the aforementioned technical features, the variable cost in the period of analysis evolves as shown next:

Table 21. Evolution of the CCGT variable cost.

		2020	2022	2024	2026	2028	2030
Variable cost	[€/MWh]	50.85	56.65	62.44	68.23	74.02	79.81

The difference between existing and not existing will be the investment cost, which will be reflected for new plants but not for existing.

On other hand, it has been considered that the new plants that will enter the system will be exclusively CCGT for several reasons:

- The system needs flexible technologies in a context of high penetration of renewables.
- Coal power plants are flexible but not environmental friendly, so new installations are not expected. The specific environmental investments so as to comply with the DEI have already been decided and done prior to the period of analysis
- Potential capacity of large hydro resources in the Spanish territory are considered to be totally exhausted, so new capacity of these plants is not possible.

f. Type of technologies

All units of the same type of technology will be considered identical. With regard to thermal units, in the following Table 22, the values considered for the net capacity of one unit of each thermal technology and their corresponding emission factor are shown.

Table 22. Type of thermal units, unitary net capacity and CO2 emission factor.

Technology	Unitary Net Capacity (MW)	Emission factor (tCO2/MWhe)
National coal	350	1.000
Imported coal old	350	0.920
Imported coal new	350	0.910
Nuclear	1000	0.000
CCGT	380	0.375

Costs of operation and maintenance of the generation fleet have been calculated for each type of plant considering variables as performance, previous emissions factor, transport cost and other variables based on average values given by (IEA, 2014).

g. Load factor (implicit assumption)

Due to consideration f, the functioning hours of each type of plant will be the same. This occurs because their bidding strategy will be the same and therefore there will not be a unique marginal unit but a marginal technology that will dispatch equally i.e. there is not a merit order across a technology

h. TYNDP according to plan

This implies that the interconnection capacity of the Iberian system with the rest of Europe will reach a maximum of 8% (REE, 2015). For this reason it has been considered from the safe side, that the contribution of the interconnection capacity to the security of the Spanish system will be null.

V.1.2. Definition of scenarios for 2020-2030

Three different likely scenarios have been defined in order to reflect the future uncertainty that the Spanish power system is facing. After defining in the previous section, which the common inputs for the scenarios are, the differences between them will be related to uncertainty in the evolution of the power installed of nuclear plants, coal plants and RES penetration. They are defined as Low, Medium and High Scenarios for expressing the level of requirements of each: the '*Low scenario'* will imply lower requirements in terms of new capacity installed, the *'High scenario'* will represent a future with the highest stress and the '*Medium scenario'* will be in between both.

For each scenario an equilibrium point has been reached and set as base case scenario. That equilibrium point consist in a situation where there will not be any CRM in place. For reaching that point in each scenario, it has been analysed whether the CCGT plants, which are the peaking units of the system, are recovering costs from the market. If this is the case, it has been considered that new plants will be willing to enter into the market as long as they would make benefits as well. Focusing on one scenario, the iterative process followed for each year of the period of study is:

1. Calculate if the benefit of the existing units in one year is positive:

$$EBIT = Income - Costs = p \cdot prod - (OFC + VarCost + InvC)$$

If:

$$EBIT < 0 \rightarrow NO\ new\ entrances$$

$$EBIT > 0 \rightarrow New\ entrances$$

2. New entrances will be considered, until the point that makes that a new entrance will lead to the non-recovery of the costs of all the entrances. This is:

   If:

$$P_{new} = n \cdot 380 \rightarrow \begin{cases} EBIT_{new} > 0 \rightarrow N = n + 1 \\ EBIT_{new} < 0 \rightarrow N = n - 1 \end{cases}$$

Where:

- $EBIT$ [€] stands for Earnings Before Interest and Taxes
- p [€/MWh] is the price of energy in the day ahead market
- $prod$ [MWh] is the energy production of the available CCGT
- OFC [€] stands for Operational Fixed Costs
- $OPEX$ [€] are the operational variable costs
- $InvC$ [€] are the annualized investment costs
- P_{new} [MW] is the capacity that enters the system
- n, N is the number of units entering the system

The specific characteristic of each of the three base case scenario are detailed in the following sections.

V.1.2.1. *Low scenario*

The main considerations in the *low scenario are:*

- ✓ The useful life of **nuclear** power plants is extended so their capacity will be available and stable during the period of study.
- ✓ Power plants fuelled with **national coal** will closed owing to their low economic competitiveness. From those which work with **imported coal**, 2 different evolutions have been distinguished:
  - o Newest plants will close after 50 years of operation.
  - o Older ones will close in 2018 since they are assumed no to undergo environmental refurbishments and therefore their emission limits will not be acceptable.
- ✓ With regard to **RES**, the projection of new capacity has been consistent with achieving penetrations of wind and solar PV around 50% at growth rates previously observed in Spain.

Applying the iterative process previously explained to the *low scenario*, it has been obtained that the market price will not attract new entrances into the system, while no CRM applied as Figure 20 shows:

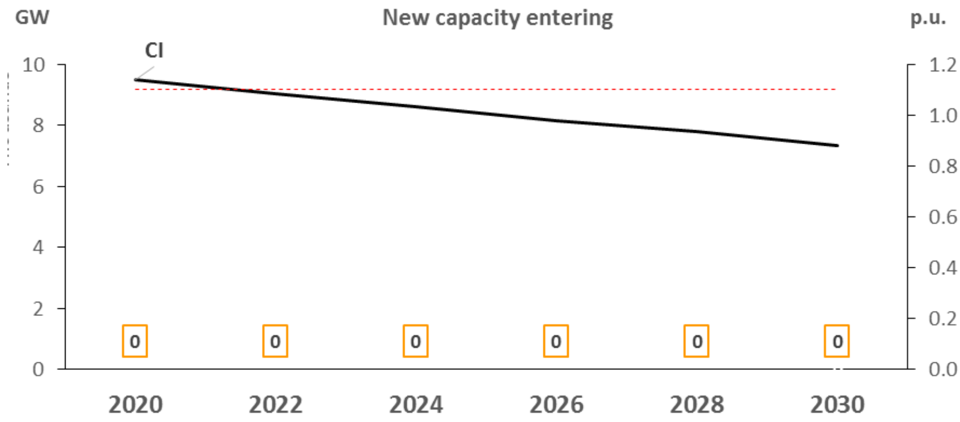


Figure 200. New capacity entering into the system without CRM in the *Low scenario*.

Under this scenario the CI will be lower than 1.1 from 2022 onwards as Figure 21 represent. As it is expected, the weighted average energy price increases until a maximum of 104 €/MWh in 2030, when the CI reaches its minimum value of 0.88.

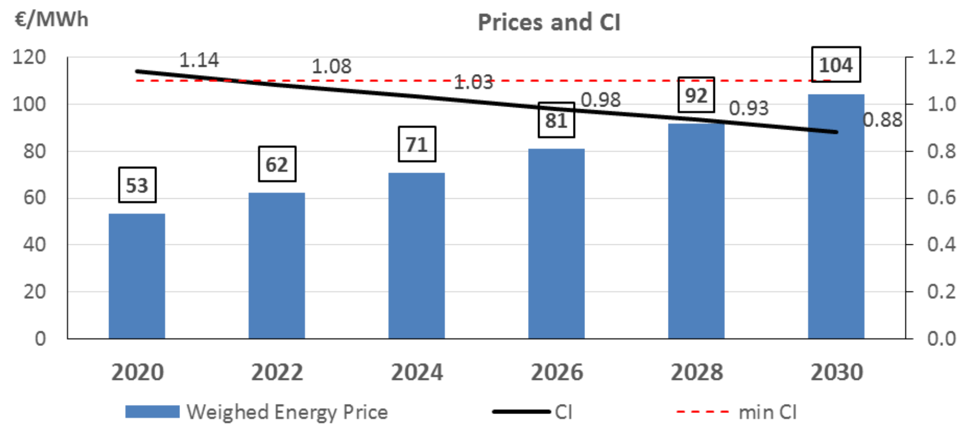


Figure 21. Weighed energy price and the CI without CRM in the *Low scenario*.

The following Figure 22 shows the firm capacity that the system would need so as to reach the minimum level of SoS.

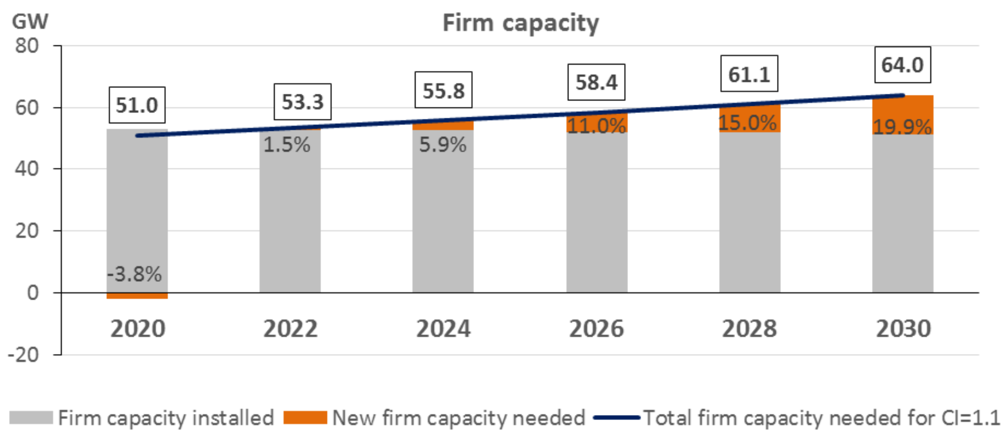


Figure 22. Firm capacity installed and needed for reaching a CI of 1.1 in the *Low scenario*.

Given the lack of capacity in the system, hours of ENS will arise from the year 2026 onwards as Figure 23 displays along with the ENS during those hours and the per thousands of the ENS over the demand.

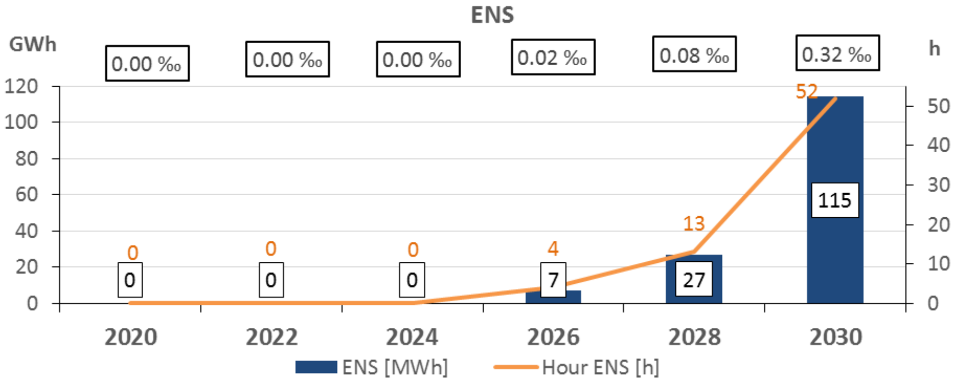


Figure 23. Hours with ENS and ENS in the *low scenario* for the period 2020-2030.

With regard to the resulting cost-recovery of the CCGT fleet, the following Figure 24 shows the EBIT of the 'existing' plants and that corresponding to the plants that will enter the system under this scenario, 'entering WO'.

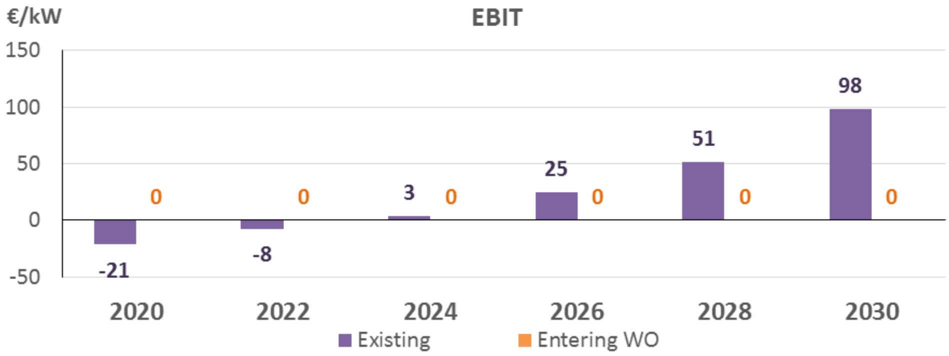


Figure 24. EBIT of the CCGT fleet in the *Low scenario*.

In is observed that under this scenario, the existing CCGT plants are still not recovering their costs in 2020 and 2022.However, from then on the tendency changes and existing plants will see how the relevant increase of the energy price will bring them significant benefits.

In the following Figure 25 the evolution of the generation fleet capacity of this low base case scenario for the period of study is presented inFigure 25:

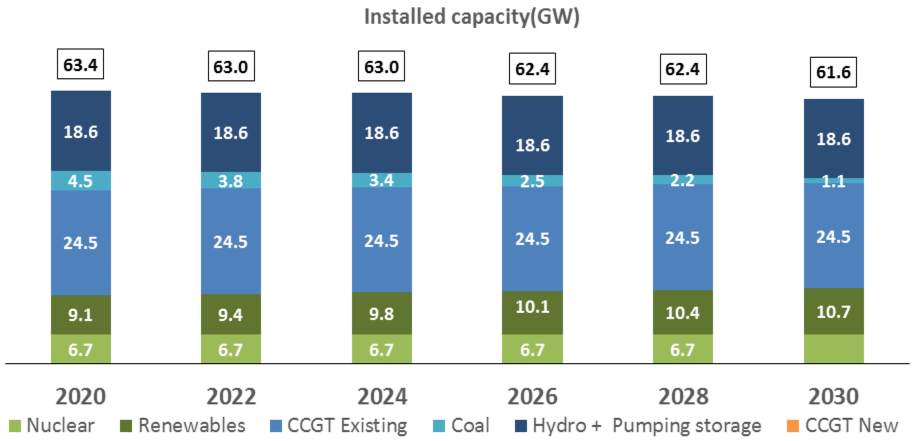


Figure 25. Installed capacity evolution in the *Low scenario*.

V.1.2.2. *Medium scenario*

The evolution of the coal power plants and RES penetration will be same as in the *low scenario*. However, the nuclear power plants life will not be extended beyond 40 years. This is:

- ✓ Nuclear power plants will close at the end of their useful life (40 years)

The same iterative process has been followed in the *medium scenario*. In this case, new plants will be attracted into the system without the need of CRM remuneration owing to the fact that tighter CI leads to higher prices and thus greater income. The capacity entering the system is shown in Figure 26.

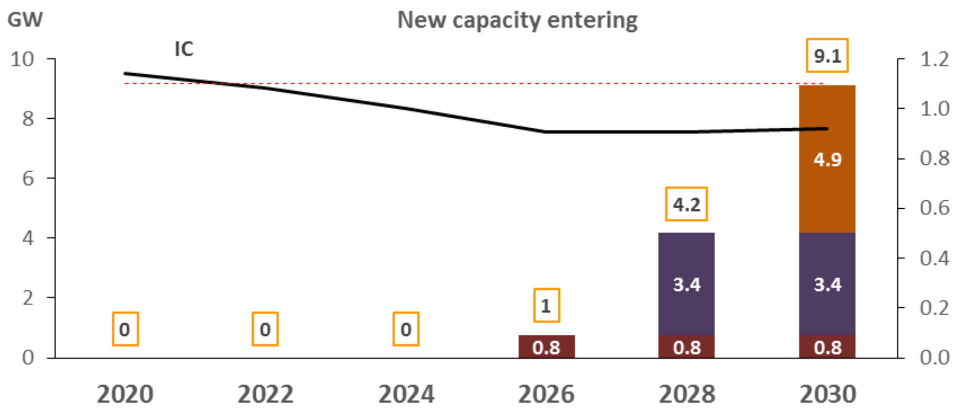


Figure 26. New capacity entering into the system without CRM in the *Medium scenario.*

As it is seen in Figure 26, under this scenario the CI (black line in the figure) will be lower than the desirable one (red line) from the year 2022 onwards. As it is expected, the energy price increases until a maximum of 106 €/MWh in 2030, this is it increases almost to the double of 2020 values (see Figure 27).

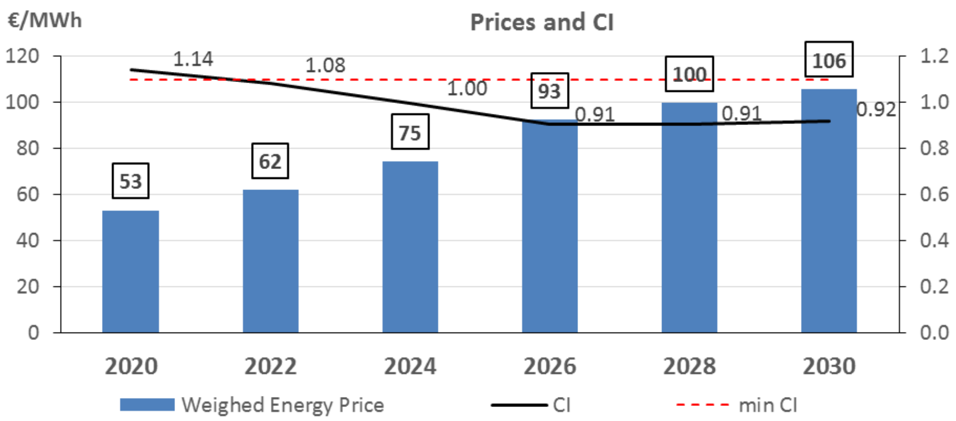


Figure 27. Weighed energy price and the CI without CRM in the *Medium scenario.*

The new entrant capacity is not enough so as to reach the minimum level of SoS, i.e. the market is not sending the right economic signal to investors. The following Figure 28 shows the firm capacity that the system needs for reaching the 1.1 target and which will be the gap of new capacity needs (orange fraction).

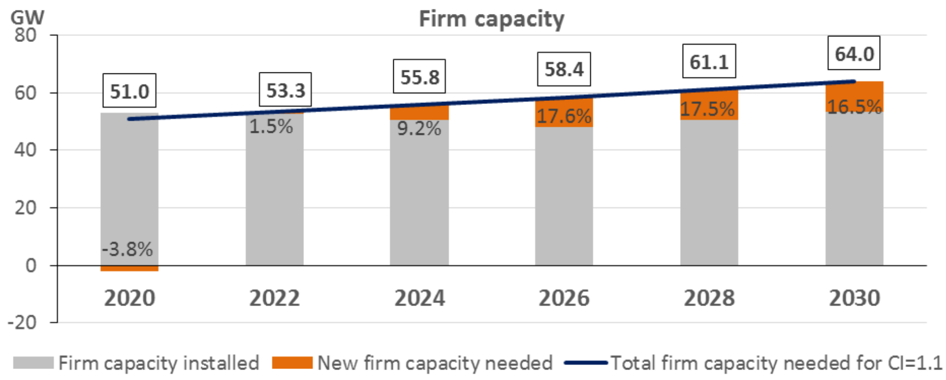


Figure 28. Firm capacity installed and needed for reaching a CI of 1.1 in the *Medium Scenario.*

Given the lack of capacity in the system, hours of ENS will arise as Figure 29 displays along with the ENS during those hours and the per thousands of the ENS over the demand.

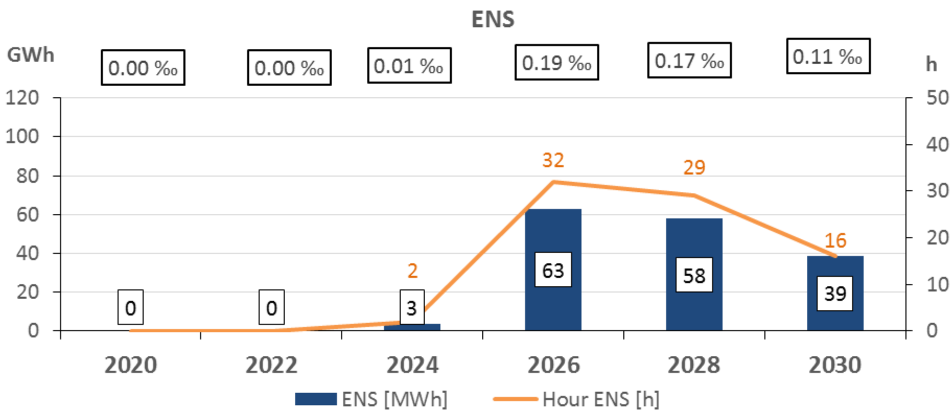


Figure 29. Hours with ENS and ENS in the *Medium scenario*.

With regard to the resulting cost-recovery of the CCGT fleet, the following Figure 30 shows the EBIT of the 'existing' plants and that corresponding to the plants that will enter the system under this scenario, 'entering WO'.

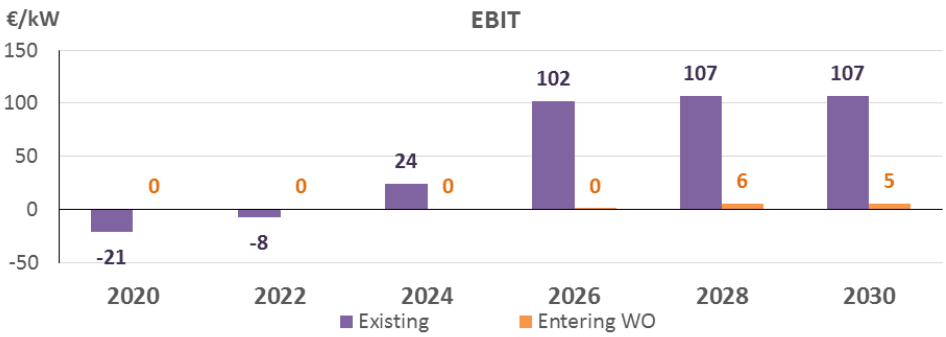


Figure 30. EBIT of the CCGT fleet in the *Medium scenario*.

It is observed as existing plants will not be recovering their cost from 2020 to 2022.From then on, the tendency changes and existing plants will see how the relevant increase of the energy price will bring them significant benefits and stable with the new entrances.

Figure 31 shows the evolution of the generation fleet capacity for the period of study:

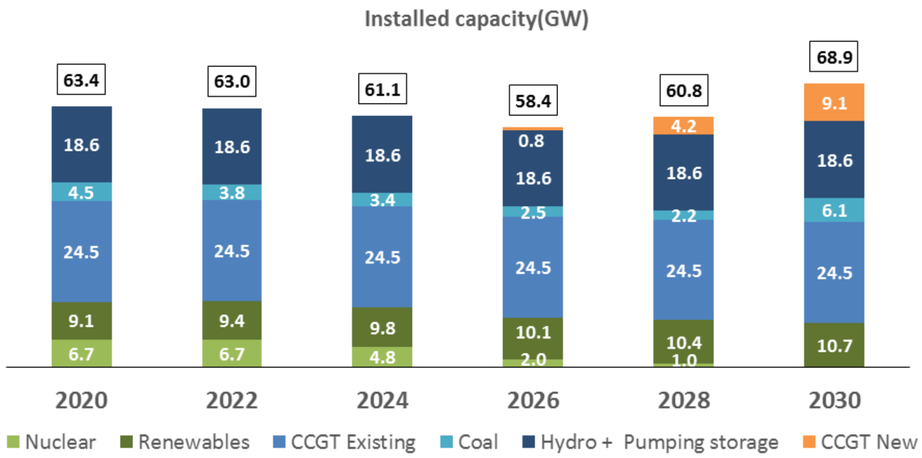


Figure 31. Installed capacity evolution in the *Medium scenario*.

V.1.2.3. *High scenario*

The scenario with the highest requirements and stressed for the SoS is the *High scenario*. It will involve the following events:

- ✓ Closure of all the coal capacity before 2020
- ✓ Closure of nuclear capacity by the end of their useful life (40 years).
- ✓ RES penetration will be more relevant in this scenario with regard to the previous scenarios. Thus, so as to represent this rate of increased growth, it will be considered that the wind generation as well as solar PV capacity will increase a 50%[18] more than in the previous scenarios.

In the *High scenario*, new plants will be attracted into the system without the need of CRM remuneration owing to the fact that tighter CI leads to higher prices and thus greater income. The capacity entering the system is shown in Figure 32.

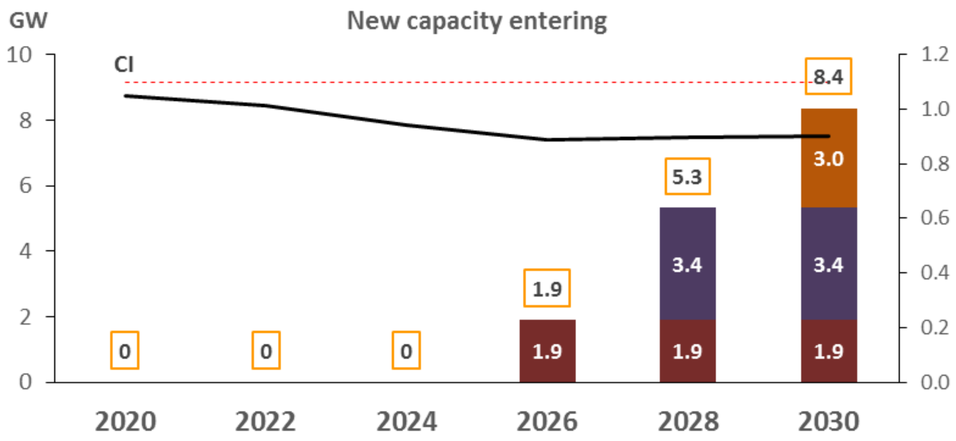


Figure 32. New capacity entering into the system without CRM in the *High scenario*.

[18] According to the vision 4 of the Scenario Outlook and Adequacy Forecast 2014-2020 (ENTSOe, 2014), wind generation capacity will increase up to 49 GW (~50% increase per year). Therefore, for the sake of simplicity this rate will be also considered for solar PV.

As it is seen in Figure 32, under this scenario the CI (black line in the figure) will be lower than the desirable one (red line) all along the period of study. As it is expected, the energy price increases an 85 % from 2020 t0 2030 till a maximum of 106 €/MWh(see Figure 33).

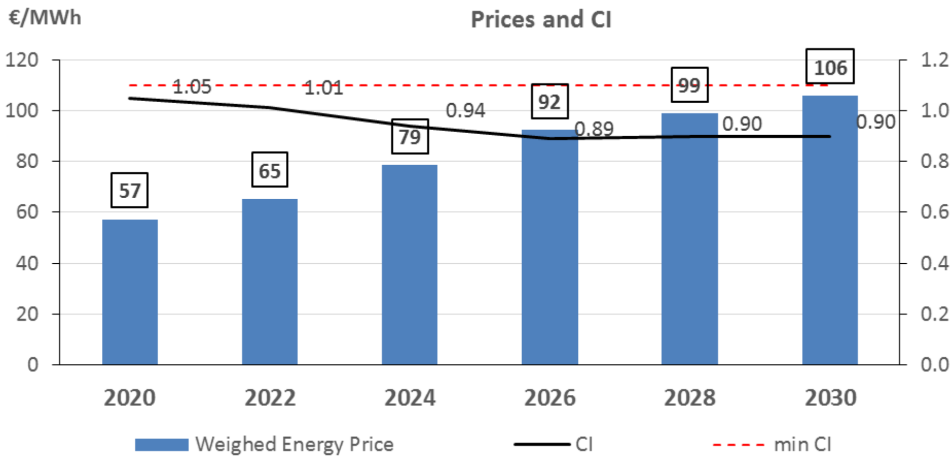


Figure 33. Weighed energy price and the CI without CRM in the *High scenario*.

The new entrant capacity is not enough so as to reach the minimum level of SoS also in this scenario. The following Figure 34 shows the firm capacity that the system needs for reaching the 1.1 target and which will be the gap of new capacity needs (orange fraction) under the *high scenario.* It is observed as the capacity gap decreased from 2026 on due to the new capacity entering the system without CRM, but it is still considerable.

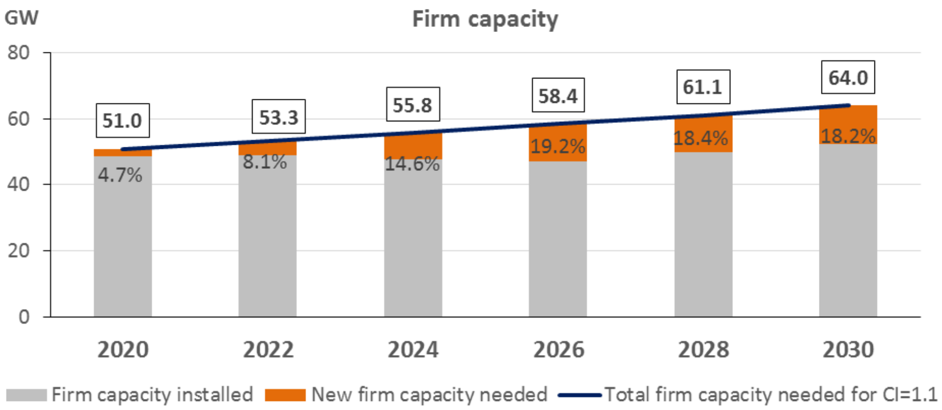


Figure 34. Firm capacity installed and needed for reaching a CI of 1.1 in the *High scenario*.

Given the lack of capacity in the system, hours of ENS will arise as Figure 35 displays along with the ENS during those hours and the per thousands of the ENS over the demand. The peak on ENS appears the year with bigger gap of firm capacity. That is to say, the year 2026.

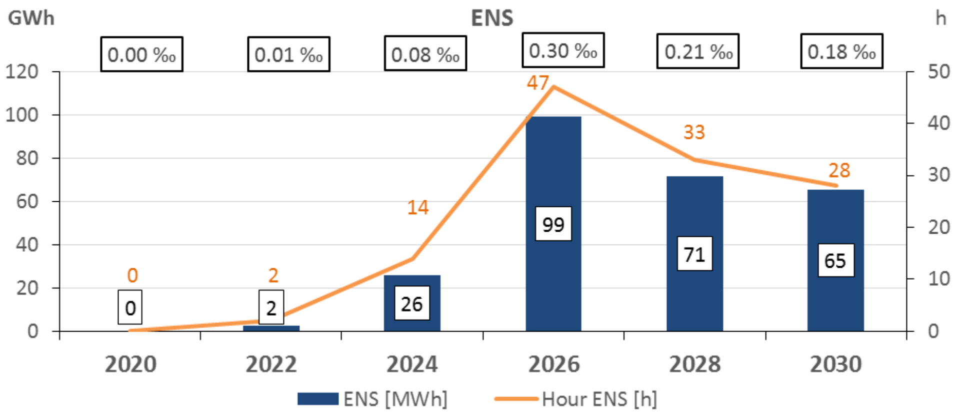


Figure 35. Hours with ENS and ENS in the *High scenario*.

With regard to the resulting cost-recovery of the CCGT fleet, the following Figure 36 shows the EBIT of the 'existing' plants and that corresponding to the plants that will enter the system under this scenario, 'entering WO'.

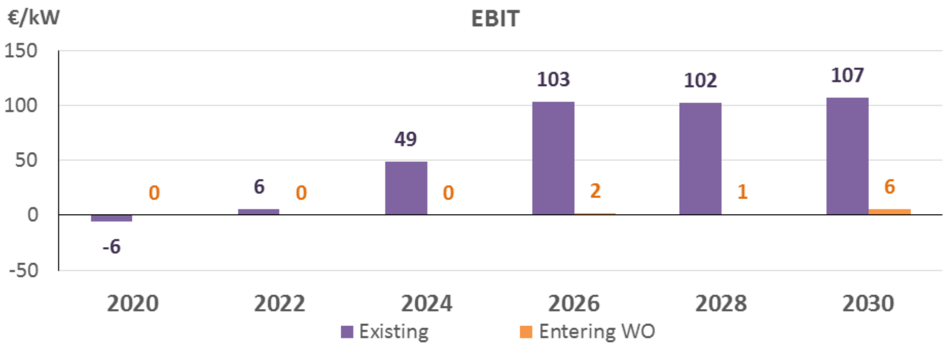


Figure 36. EBIT of the CCGT fleet in the *High scenario*.

It is clearly seen as the existing plants will be recovering their cost from 2022 onwards. The relevant increase of the energy price will bring them significant benefits that remain quite stable due to the entrance of new capacity.

Figure 31 shows the evolution of the generation fleet capacity for the period of study:

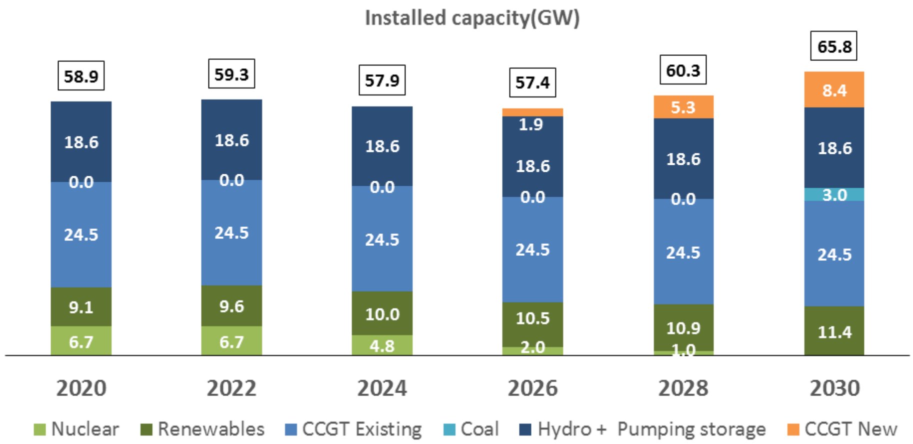


Figure 37. Installed capacity evolution in the *High scenario*.

V.2. ALTERNATIVES OF CRM IN THE SPANISH POWER INDUSTRY

Now, we know which are the requirements of the Spanish system, that is to say, we know the new installed capacity that should be brought into the system so as to comply with the 1.1 CI targeted in each of the three plausible scenarios studied (see figure x, Figure 28, figure z).

Then, it is time to carefully select which types of CRM among the studied will best fit with our particular SoS problem and for the actual design, characteristics of the Spanish power system.

V.2.1. Selection of the CRM types to be assessed

With the study carried out in the previous section, it can be concluded that the SoS problem in the Spanish power system is a systemic problem that remains along the period of study. If no CRM is applied, the capacity that would enter the system would not be enough so as to comply with the reliability standard (as represented in figures x, Figure 27, figure z). Therefore, hours with ENS arise under the assumptions of the three scenarios and the CRM to implement should be focused on bringing new capacity into the system. In the same way, it is considered also necessary to foster availability of existing technologies in the medium term as a back-up of the already relevant presence of inflexible and intermittent RES generation.

Let's then, in the light of the results released from the state of the art analysis carried out, select the proper type of mechanism:

- **Strategic reserves** are aimed mainly at solving shorter term SoS issues that would not remain in the long term. For this reason, they try to avoid mothballing and not to foster new investments.
- **Tenders for new capacity** could be appropriate if the Spanish problem would be transitional, however, it is seen with the study of a plausible future of the sector, that SoS concerns will occur all along the decade and even further. Therefore, a solid mechanism that would remain in the system indefinitely should be design, taking into account that investors will need stable and efficient investment signals so as to build the capacity that the system will need.
- **Capacity payment**s are against all good-practices guidelines on CRM implementation given that it has been demonstrated that they do not reveal the true value of capacity. Setting administratively the level of remuneration hampering the cost-effectiveness of CRM on bringing the right amount of capacity that the system needs. The study of the Spanish experience with capacity payments calls for a new CRM that enables a reasonable profitability for agents and dodge the future risk of under-procurement.

Therefore, for all of the above and in the light of state of the are carried out in CHAPTER III: , the EC guidelines and the study of the particular difficulty of the Spanish power sector in sending the right economic signals for foster investments in new efficient and flexible capacity, it is recommended to implement a **capacity market**. Among the three types of capacity markets studied:

- A **decentralized obligation mechanism** is dismissed due to, as explained in subsection C.2.2, long term contracts would be necessary to emerge so as to represent a solid investment signal for investors. Owing to the high uncertainty that characterizes the Spanish power system nowadays and, therefore, the unpredictable evolution of markets prices, this mechanism is not considered as appropriated.

The remaining types of mechanisms, namely centralized auction and the reliability option scheme, are considered to be more suitable to adapt to the current capacity payment mechanism that still will be in place in the period of study.

If well design, both CRM will be able to addressed SoS in a cost-efficient way without distorting the proper functioning of markets. Additionally, also the CNE reached to this conclusion in its proposals of a new CRM (CNE, 2012b) and proposed an investment incentive allocated through an auction procedure. Additionally, following this proposal, a specific availability incentive will be considered so as to incentivize those existing plants that are not recovering their costs. It is necessary to foster availability of existing technologies in the medium term as a back-up of the already relevant presence of inflexible and intermittent RES generation. As the CNE pointed, this mechanism will be in line with EC guidelines considering that a unique mechanism to face two different problems might not bring the proper amount of capacity needed[19].

In summary, the following section presents two alternatives of CRM base on:

1. a **central buyer model (capacity market CM)**
2. a **reliability option (RO)**.

The design variables initially considered in terms of eligibility and allocation process will be common for both types of mechanism. The main difference will be in the definition of the reliability product given that in the first case there is an annual payment while the second case it will be a call option contract. This availability incentive will take the form of a central buyer model quite similar to the one proposed for incentivizing investments. Their main characteristics will be treated in next section.

V.2.2. **Design and implementation of CRM design alternatives for Spain**

In this section a general design of the alternatives is given. It has to be taken into account that the final designs will be the result of the assessment that will be carried out in following section 83VI.1. . More specific design variables will be selected after simulating and evaluating their influence under the different scenarios studied in terms of system regulated costs, market prices, level of adequacy, efficiency and cost recovery of generating plants.

On the other hand, some other designing values will be ex-ante set. This is owing to the fact that after the deep study made in chapters II and III, a solid conclusion can be made.

V.2.2.1. *Common design variables for the alternatives*

<u>Eligibility criteria</u>

The auction should be opened to existing and new generators, demand side response (DSR) operators, storage operators and interconnectors[20] however, this will be defined after

[19] This is the case of the capacity market in UK, which has not bring the amount of new capacity needed into the system and, therefore, the design of the CRM is nowadays under debate.

[20] The CNE allowed cross border participation in its proposal (CNE, 2012b) offering capacity up to the maximum that the interconnector permits and taken into account that 'double counting' has to be avoided.

analysing its effect on the system regulated cost as well as its contribution to the reliability standard fulfilment.

The exception to participate applied to capacity that receives support from other measures such as renewable power plants with incentives. However, capacity that participates in other market mechanism such the balancing services, can participate as well.

Despite it is intended to be a technology neutral mechanism, other requirements such as being non-intermittent or programmable might probably implicitly exclude some technologies. This requirements could be those that apply for the participation in the balancing services[21]. Additionally, the proper design of the reliability product (obligation and penalty) will also implicitly hindrance capacity providers that do not comply with certain conditions such as high efficiency level or wide ramp-up/down limits.

Availability requirements will apply, such us a minimum firm capacity (understood as the expected capacity available in specific periods). This requisite tends to discourage the participation of RES generation because of the uncertainty of its production and thus their risk of being penalized.

For the purpose of assuring the effective commissioning of the plant after the lag period, it could be required to participants to be holder of the Integral Environmental Authorisation (AAI from the Spanish *Autorización Ambiental Integrada*). However, if this would mean a significant reduction of the expected participation, the contract could be subject to a commitment of getting the AAI within a specified period (e.g. 1 year). Moreover it should be required collateral in the form of bank guarantees, having a solid business plan and/or present a specified level of creditworthiness.

Participation in the CM is not mandatory, but the capacity than can participate will have a maximum ceiling corresponding to the firm capacity, calculated as the product of the installed capacity of the plant times the firmness coefficient that REE sets for each plant type (see Table 16).

Other relevant consideration could be the requirement of holding fuel supply contracts that guarantee a seamless functioning of 16 hours during 15 days[22].

<u>Allocation process</u>

Both alternatives will involve a central competitive process in which all capacity providers will offer their capacity, where REE will play the role of central counterparty, that is to say, it will buy the capacity on behalf of electricity suppliers/consumers. This auction will take place once a year, after REE has announced the strike price that will be applied. Complementary auctions will be considered in order to allow agents to renegotiate their contracts and adapt to possible variations of the capacity target that REE might require. Furthermore, a secondary market will be opened to trading contracts from 1 year to one month before the delivery period, so as to permit agents to hedge their positions in a continuous basis when more accurate demand forecasts are available. This risk hedging tool is important for enabling DSR capacity to actively participate in the mechanism.

The target capacity to be made available will be determined ex ante by REE. It is considered that four months in advance would be enough so as to permit agents to study and prepare

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[21] This requirements can be found in the Generation-demand unbalance management stablished in the Operational Procedure 3.3, include in (Gobierno de España, 2015).

[22] These values were recommended by the CNE in its proposal for a new CRM, which can be consulted in (CNE, 2012b).

their offers for the auction. It would be interesting the provision of a capacity demand curve with the intention to give flexibility on the amount of capacity to contract depending on the cost, however, this would be other study that falls apart from the scope of this study. Therefore, in the simulations that will be later on carried out, pure quantity-based mechanism will be considered. This and other simplification made for the adaptation of the alternative CRMs to the model will be explained in the following section VI.1. .

The auctions will take the form of a descending clock, pay-as-clear auction where they can decide how much capacity they will be willing to provide up to a maximum amount corresponding to its firm capacity.

To mitigate market power, new entrants and DSR resources will be classified as price makers, and will be free to bid up to the overall auction price cap. The rest of participants will be classified as 'price takers' (who cannot set the price).

<u>Capacity product definition</u>

The main auction will be held 4 years ahead of the beginning of the obligation, given that this lag period is considered appropriate for allowing the new capacity sought to build and commission the plant. However, a complementary auction 1 year ahead would be recommended for fostering participation of demand and storage providers and to allow the adjustment of capacity required when more precise information will be available. Additionally, a secondary market will be settled so as to permit agent to trade their obligations, so as to provide a risk hedging tool that will foster more participation in the mechanism.

In order to maintain liquidity and have good price signal of scarcity, one obligation of participants will be to submit offers in the day-ahead market for all their contracted capacity. Any remaining capacity will have to be bid into the ancillary services market and balancing markets. As it has been defined in the eligibility criteria, new plants that do not withhold an AAI will be excluded from the mechanism.

It is considered that units not dispatched will be exempted of their firm capacity commitment. However, penalties also will applied in intraday and ancillary services markets, in order to avoid generators selling capacity in the DAM market and buying it back in the following markets for avoiding the penalty.

Contractual agreements are available for different lengths for the different types of participant. New generators could qualify for agreements of a maximum of 15 years. Generators who invest to renovate or restore an existing asset can qualify for agreement of up to 3 years. Current generators and DSR and storage and interconnectors, will be eligible for 1 year agreements.

V.2.2.2. *Alternative 1: Capacity market (CM)*

<u>Capacity product definition</u>

In this mechanism, the nature of the obligation of the capacity providers with capacity awarded in the auction will consist on being available and effectively supply energy in moment of system stress in exchange of a remuneration that will be calculated as follows:

$$Remuneration_y \left[\frac{€}{year}\right] = Premium \ \left[\frac{€}{MW}\right] \cdot Capacity\ Contracted\ [MW]$$

The premium will be the clearing price of the auction and capacity contracted will be the capacity committed.

Once the lag period has gone by, the capacity providers should be ready to fulfil their obligations. The period of obligation should be defined in advance of each delivery year by REE. They should fall into moments of scarcity, that do not necessary have to coincide with those of peak hours of the system, owing to the fact stress situations may also arise during periods of high RES production that would imply the need of significant back-up generation. For this reason, it would be recommended to define these periods according to the thermal gap in each hour[23]. A scarcity price could also be set.

V.2.2.3. *Alternative 2: Reliability Option mechanism (RO)*

The mechanism consist in a capacity market where an auction is organized centrally and where the capacity product is a reliability option. Participants that will get an agreement in the auction with a successful bid will be awarded with a steady payment during the duration of the capacity agreement in return for a commitment to deliver electricity at times of system stress which will be those where the market price. In case of not completion of the obligations, penalties apply.

<u>Capacity product definition</u>

The capacity product is a reliability option. Participants that will get an agreement in the auction with a successful bid will be awarded with a steady payment during the duration of the capacity agreement in return for a commitment to deliver electricity at times of system stress which will be those marked by the market price *s* overpassing the so called strike price *k.* At that moments, capacity providers holder of a RO contract are also obliged to pay to REE any positive difference between *(s-k)* for the capacity contracted and during the contract duration. The price selected as a reference will be the day-ahead market price.

The remuneration given in return of the availability obligation will be the premium (€/MW-year) set by the auction clearing price, for their capacity obligation (MW-year) which is the clearing quantity committed.

$$Remuneration_y \left[\frac{€}{year}\right] = Premium \left[\frac{€}{MW}\right] \cdot Capacity\ Contracted\ [MW]$$

$$Implicit\ penalty[€] = (s-k)\left[\frac{€}{MWh}\right] \cdot Capacity\ Contracted\ [MW] \cdot Time_{s>k}[h]$$

The strike price will be the variable cost of the most expensive peaking unit that might be reasonably required to serve load increased by a 10% (variations of this value could be considered). For this case study, the reference marginal cost will correspond to the one of a new built CCGT plant.

In case, the responsible party would not meet its obligation when required, an explicit penalty *pen* will apply. This value could be set at twice the strike price and will discriminate between old and new plants. The penalty would be subject to the part of the capacity committed not delivered calculated as follows:

$$Explicit\ penalty = pen\ \cdot (Capacity\ contracted - capacity\ not\ delivered) \cdot\ Time_{s>k}[h]$$

V.2.2.4. *Availability incentive*

The main objective of this mechanism (that should be intended as a complementary auction to the CRM proposed) will be to solve the gap that existing plants present. It will work as the central buyer model. Nevertheless, in this case the auctions will take place one year before the delivery period and the contract length will be one year. Due to this fact, new

[23] This gap is calculated as the sum of real production of CCGT and coal power plants (CNE, 2012b).

generation capacity will implicitly be excluded whereas existing plants, DSR and storage provider will be fostered to participate.

V.2.2.5. *Summary of the design variables of the proposed CRM*

Table 23. Summary of the design variables of the proposed CRM

	Alternative 1:CM	Alternative 2: RO	Availability Incentive (AV.INC)
Necessity	Investment incentive		Availability incentive
Eligibility	Existing and new generators, DSR operators, storage operators and interconnectors. More focused on participation of new plants.		Existing and new generators, DSR operators, storage operators and interconnectors. More focused on participation of existing plants.
Allocation process	Central Auction (Main auction)		Central auction (Complementary auction of to the CM or RO auction)
Remuneration	Premium at the auction clearing price (€/MW/year).		
Lead time	4 years		1 year
Contract duration	New built: 15 years. Refurbishing: 3 years. Existing and DSR, interconnectors: 1 year		1 year
Obligation	Being available when the thermal gap is high.	Return any positive difference between the spot and the strike price.	Being available when the thermal gap is high.

V.2.3. **Proposed method**

With the aim of analysing the performance of each of the CRM alternatives made, they have been introduced in the model and simulated in the three scenarios. The output searched was to reach a minimum CI of 1.1 every year. That is to say, to incentivise new installed capacity to comply with that limit. The CI is calculated as follows:

$$CI_{y,s} = \frac{Total\ Firm\ Capacity_{y,s}(MW)}{Annual\ Peak\ demand_{y,s}\ (MW)} = \frac{\sum_i Net\ Capacity_{y,i} \cdot Firmness\ coefficient_i}{Annual\ Peak\ demand_{y,s}}$$

Where:

- $Annual\ Peak\ demand_{y,s}$ is the maximum hourly demand expected in the year y under the scenario *s.*
- $Net\ Capacity_{y,i}$ is the total net capacity of the technology *i* in the year y
- $Firmness\ coefficient_i$ is the firmness coefficient of the technology *i.*

It has been considered that the capacity that would enter into the system through the mechanism in a year y for achieving a CI equal to 1.1 is obtained as follows:

$$CI = 1.1 = \frac{Total\ Firm\ Capacity\ (MW) + New\ Firm\ capacity\ (MW)}{Annual\ Peak\ demand\ (MW)} \rightarrow$$

$$New\ Firm\ capacity = 1.1 \cdot\ Annual\ Peak\ demand -\ Total\ Firm\ Capacity$$

Once, this value has been obtained for every year of study, a simulation is carried out considering that it is exactly what enters the system through a capacity market (CM) or a reliability option (RO). Then, the variables that will serve us to assess the alternatives will be calculated and represent. But first of all, it is necessary to consider how the capacity providers, holders of a capacity market contract, would bid in the market.

Bidding strategy

It is widely known ideally, in a perfectly adapted mix, agents bidding their variable cost would make them recovery exactly their cost. However, in the real life this is not generally like this. When the margin is tight, that is to say, it is far from the 1.1 targeted and all the unit become somewhat pivotal, agent will be able to bid higher form its variable cost without risk of falling out of the dispatch. On the other hand, when we are getting close to the target, this incentive to bid higher disappears progressively, owing to that fact they will have the risk of not being dispatched.

In order to represent this bidding strategy, a parameter α has been introduced in the model. It corresponds to the slope of agents' bid with respect to the CI. It has been considered that agents will bid a maximum of a α_{max}% over their variable cost when the CI will be equal to or lower than CI_{min}. Likewise, it is set a maximum value CI CI_{max} beyond which agents will bid exactly at their variable cost, in other words, $\alpha_{min} = 0\%$.

For this case study, the values considered for these parameters are shown in Table 24and a graphical representation is depicted in Figure 38.

Table 24. Bidding strategy parameters.

Parameter α	Coverage index CI
$\alpha_{max} = 60\ \%$	$CI_{min} = 0.9$
$\alpha_{min} = 0\ \%$	$CI_{max} = 1.2$

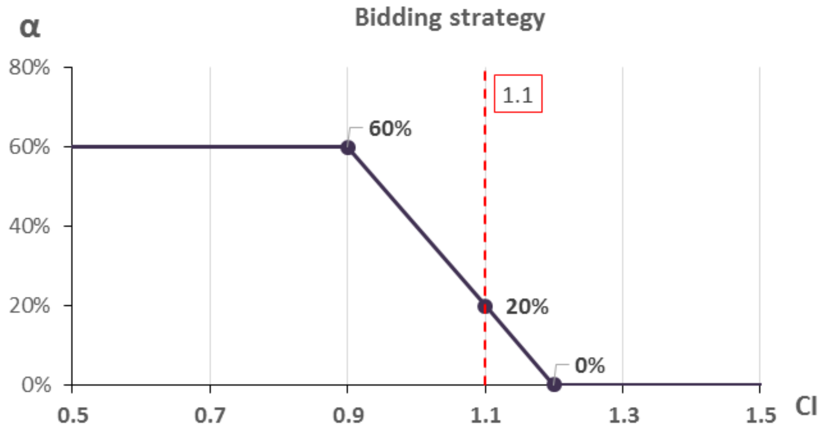

Figure 38. Bidding strategy of agents represented through the parameter α.

Up to this point there is no difference between both mechanisms proposed. Once how agents bid in the market is known, the model can be run so as to get the how much these contracts would cost for the system. Depending on the alternatives the costs will differed as follows:

V.2.3.1. *Costs of the alternative 1: CM*

In the case of this Capacity Market, it is considered that from the point of view of the regulator, the premium would ideally be exactly equal to the one that would net out their benefit. This is:

$$EBIT_{New} = Income - Costs + Premium_{CM} = 0$$

$$Premium_{CM} = -Income + Costs = -p \cdot prod + (OFC + VarCost + InvC)$$

It has to be taken into account that this equation will have implicitly an 8.5% interest rate over the investment cost.

Using this equation and taking into account the capacity that is entering the system each year, the cost that this mechanism will imply will be:

$$CM\ Cost = Premium_{CM} \cdot New\ Firm\ Capacity$$

This situation of new capacity entering the system will imply losses for the existing CCGT fleet as energy prices are reduced. For this reason, this capacity will receive an availability incentive so as to, once again, make them recover their cost. That is to say:

$$EBIT_{Existing} = Income - Costs + Premium_{AV.INC} = 0$$

Therefore, ideally the cost of the availability system will be:

$$AV.INC\ Cost = Premium_{AV.INC} \cdot Existing\ Firm\ Capacity$$

V.2.3.2. *Costs of the alternative 2: RO*

In the case of this Reliability Option, it is considered that from the point of view of the regulator, the premium would ideally be exactly equal to the one that would net out their benefit. This is:

$$EBIT_{New} = Income - Costs + Premium_{RO} = 0$$

However, in this case there will be other term included in the part of costs i.e. the implicit penalty of the reliability option. The ideal premium from the point of view of the regulator will be then:

$$Premium_{CM} = -p \cdot prod + (OFC + VarCost + InvC) + (s - k) \cdot CapacityContracted \cdot Time_{s>k}$$

It has to be taken into account that this equation will have implicitly an 8.5% interest rate over the investment cost.

Using this equation and taken into account the capacity that is entering the system each year, the cost that this mechanism will imply will be:

$$RO\ Cost = Premium_{RO} \cdot New\ Firm\ Capacity$$

This situation of new capacity entering the system will imply losses for the existing CCGT fleet. For this reason, this capacity will receive an availability incentive so as to, once again, make them recover their cost. That is to say:

$$EBIT_{Existing} = Income - Costs + Premium_{AV.INC} = 0$$

Therefore, ideally the cost of the availability system will be:

$$AV.INC\ Cost = Premium_{AV.INC} \cdot Existing\ Firm\ Capacity$$

V.2.3.3. *Summary of the methodology followed*

The process carried out for each of the three scenarios could be summarize as follows:

1) Calculation of the new capacity needed to get a 1.1 CI every year from 2020 to 2030.
2) Cost of the CRM, this is, how much the regulator will have to pay to capacity providers in exchange of their capacity
3) Resulting Weighed energy price
4) Cost of the availability incentive that existing plants will need so as to recover their 'missing money'.
5) Total costs, understand as the sum of the energy cost, the CRM (CM or RO) cost and the availability incentive (AV.INC) costs[24].

The step one will be independent from the alternative in study, whereas the results from the application of the steps 2 to 5 will be individually for each alternative. Next sections present the results of this process for each scenario.

[24] In this study, other components of the final electricity costs for consumer it has not being included owing to is has to be considered to have no impact on the assessment of alternatives.

CHAPTER VI: Presentation of results

The main objective of this chapter is to assess the impact of the two alternative design of CRM into the system. This will be done in terms of system regulated costs, cost recovery of generators and energy prices and this will be compared with the corresponding base case scenario introduced in V.1.2. . For this purpose, chapter VI is divided in two sections, namely:

1. Section 1 presents the results obtained from the simulations in an aggregated way. That is to say, for each of the three scenarios, the 3 possible market possibilities are compared so as to critically assess the alternatives made in the previous chapter.
2. Section 2 is aimed at extracting more solid conclusion about the suitability of one alternative against the other, i.e. CM vs RO. For this purpose, a sensitivity analysis will be carried out for measuring the impact that a variation of selected variables (such as a lower demand growth rate or a longer amortization period of the investments) will have in terms of system regulated costs, cost recovery of units and energy prices.

As output of this analysis, solid conclusions will be given in the following CHAPTER VII: .

VI.1. SIMULATION OF THE CRM PROPOSED IN EACH SCENARIOS

In order to make easier the visualization of the results, a code with colors and abbreviations has been used. It is shown in Table 25:

Table 25. Color codes and abbreviations used in the representations.

	CCGT Existing	Capacity already installed at the beginning of the period of study
	CCGT New	Capacity that enters the system during the period of study
	WO	Relative to the base case scenario: Without CRM
	CM	Relative to alternative 1: the Capacity Market
	RO	Relative to alternative 2: the Reliability Option

Next section shows the results obtained from the simulations by following the methodology introduced in previous 80V.2.3. .

VI.1.1. Low scenario

The following Figure 39 shows the net capacity that will enter the system each year of the period so as to reach the targeted CI:

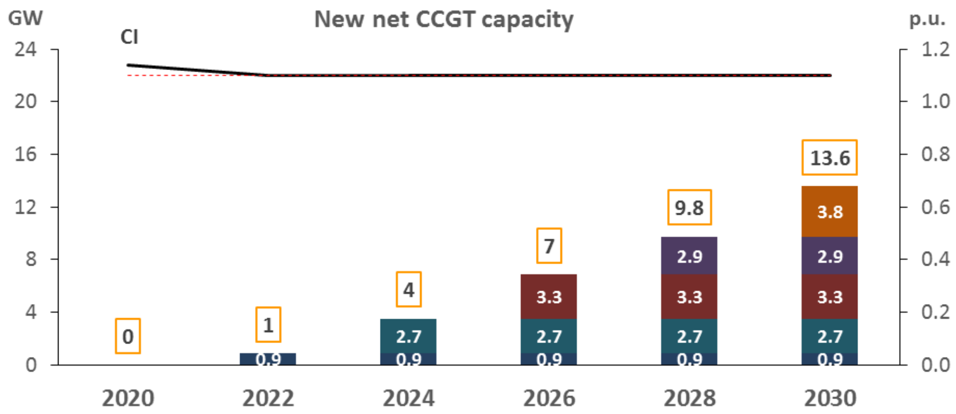

Figure 39. Net CCGT capacity that enters the system with CRM in the *Low scenario*.

It is observed in this figures that in the *low scenario* capacity will be entering the system every year since 2022 for reaching an accumulated new installed capacity of 13.6 GW at the end of the period. This means that an auction will take place every year since the first one, which will take place 4 years prior to the first delivery period i.e. the year 2018.

VI.1.1.1. *Alternative 1: CM*

Let's first see, how much would be the benefit of the plants if no incentives were applied taken into account their cost and the only income that is what they get from the market. The results are shown in next Figure 40Figure 51:

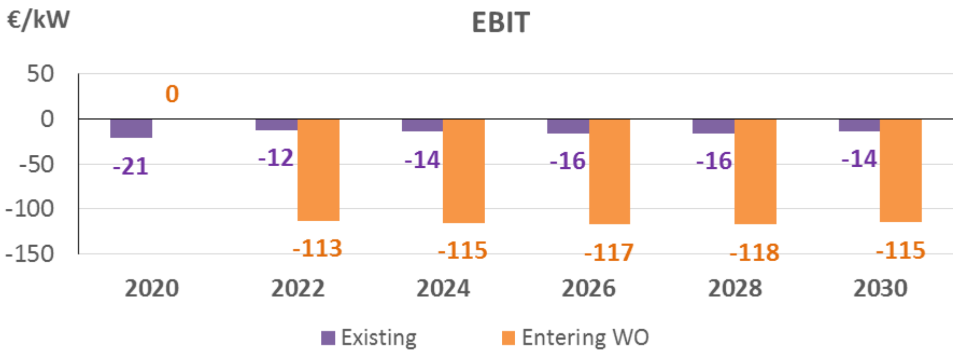

Figure 40. EBIT of CCGT fleet if no incentives applied in the *Low scenario* with CM.

Following the process explained in V.2.3. the results obtained are those ofFigure 41:

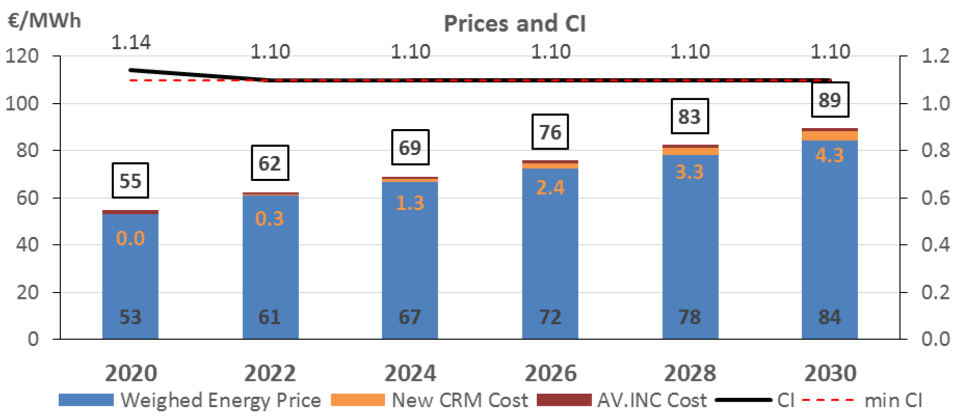

Figure 41. Energy price, CRM cost, AV.INC cost and the CI in the *Low scenario* with CM.

In this figure it is appreciated the proportion of the CRM cost with respect to the energy price. It is small but more it is the availability incentive cost. These costs decrease also along the period due to the increment of energy prices and the subsequent increment of incomes. The CM cost increases along the period due to the increase of entrances since 2020 onwards.

VI.1.1.2. *Alternative 2: RO*

As in the case of a CM, the same process is followed for the RO. Then, let's first see, how much would be the benefit of the plants if no incentives were applied taken into account their cost and the only income that is what they get from the market. The results are shown in next Figure 42:

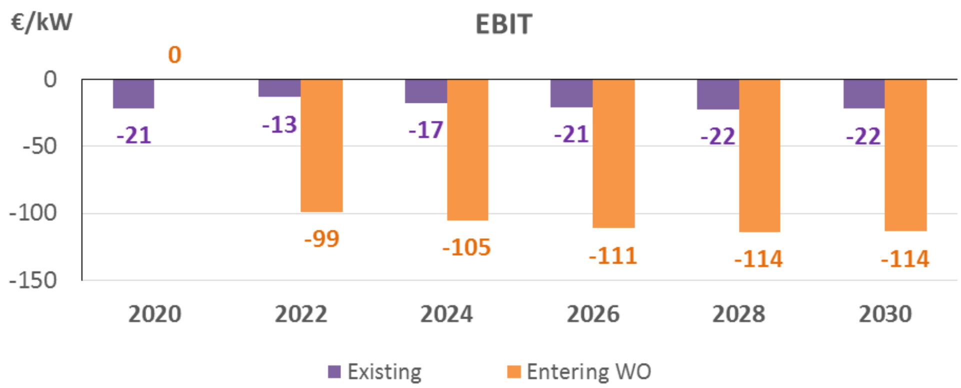

Figure 42. EBIT of CCGT fleet if no incentives applied in the *Low scenario* with RO.

Following the process as in previous scenarios, the results obtained are those of Figure 43:

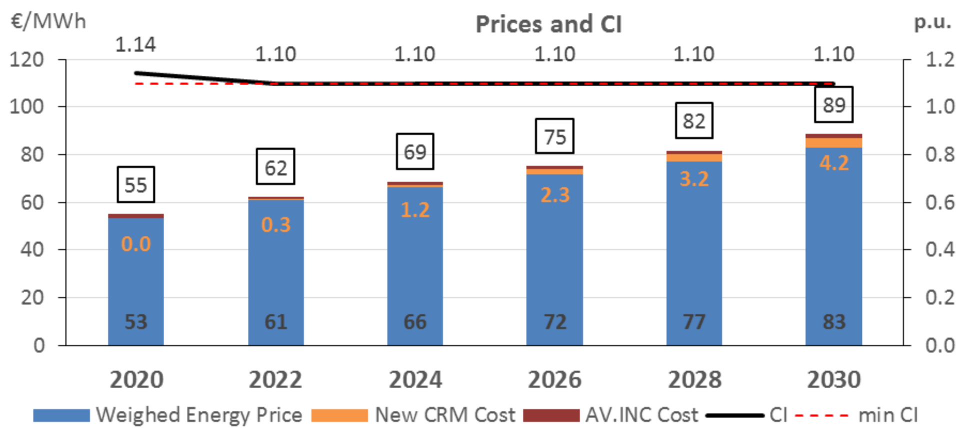

Figure 43. Energy price, CRM cost, AV.INC cost and the CI in the *Low scenario* with RO.

In a first look, this figure seems to reveal the same conclusions as the corresponding to the CM (see Figure 52): the proportion of the CRM cost with respect to the energy price is small but more it is the availability incentive cost. The RO cost increases along the period due to the increase of entrances since 2020 onwards. On the other hand, the availability incentive does not have a clear tendency.

In the following Figure 44 the load factor of CCGT unit is shown:

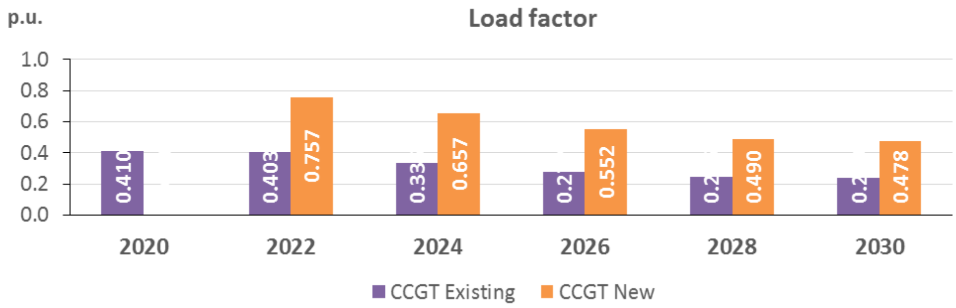

Figure 44. Load factor of CCGT units in the Low scenario with RO.

In this case, it is observed as existing and new units have a much different load factor (in the CM all CCGT units have the same load factor). Despite all units of the same type are equal, holders of RO are dispatch more than existing units due to, in general terms, RO units bid lower than the existing units when the market price is near the strike. Therefore they will work more hours than existing one as Figure 44.

VI.1.1.3. *Comparative analysis of the alternatives*

In this section, an assessment of the two alternative is done. For this aim, it is presented a comparison between them in terms of energy cost for consumers, contribution to the system regulated costs of the mechanisms and cost recovery of generators.

First of all, Figure 45 presents the weighed energy price resulting from the implementation of these mechanism (CM and RO), and it is compared also with the base case scenario where no capacity were in place (WO).

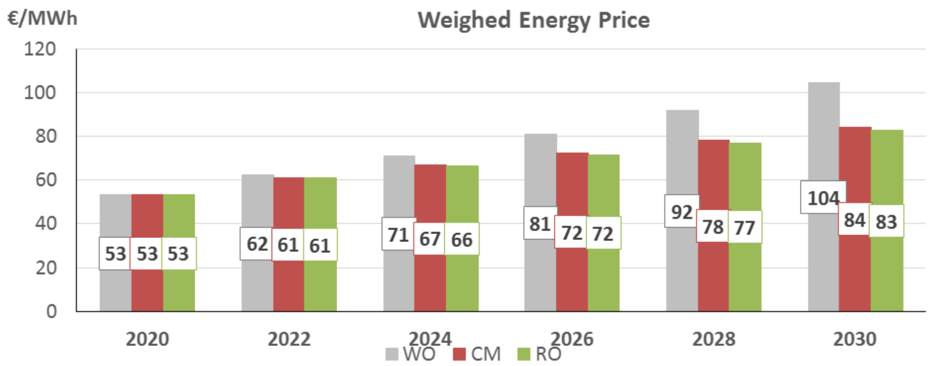

Figure 45. Comparison of the weighed energy price in the *Low scenario* for the period 2020-2030.

It is observed, as it was expected, that the energy price for consumers would be the highest in the WO case, due to the high costs of the ENS. When comparing the resulting energy price of applying a CM with a RO, it is perceived that the energy price is lower in the case of RO. This difference appears due to the effect of the strike as a price cap in the market price.

With regard to the cost of the mechanism, Figure 46 shows the cost per MWh of energy demanded that the CRM suppose.

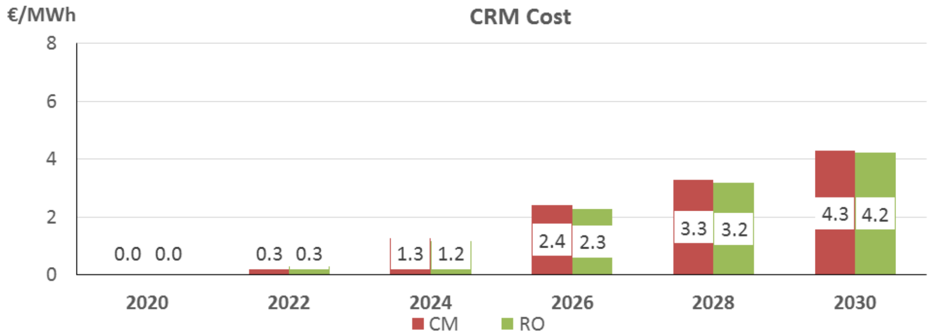

Figure 46. Comparison of the CRM costs in the *Low scenario* for the period 2020-2030.

It is observed that the RO alternative leads to more economic cost per MWh of energy demanded from 2022 to 2028.

First of all, as it is seen inFigure 45, energy prices are higher when CM mechanism applied. So it could lead to the wrong conclusion that these units are recovering more fixed cost form the market and thus they are asking for less premium to the regulator, but as Figure 46 this is not the case i.e. the cost of the mechanism is higher because they are asking more premium.

Then, why CM unit are recovering less from the market? The only reason can be the energy production difference. CM units are producing less hours than RO units due to the strategic bidding of the CCGT fleet. As the previous Figure 46 shown, in general terms, RO units bid lower than the existing units, therefore they will work more hours than them. In the same way, in the CM mechanism both new and existing units will bid the same under all circumstances so they all will work the same number of hours.

With regard to the availability incentive cost, Figure 47 shows as all along the period of study, incentivising the availability of existing plants is more costly for those coexisting with a reliability option mechanism. This is a direct result of the lower prices of energy characteristic of the cap due to the strike price and the subsequent reduction of the incomes of generators.

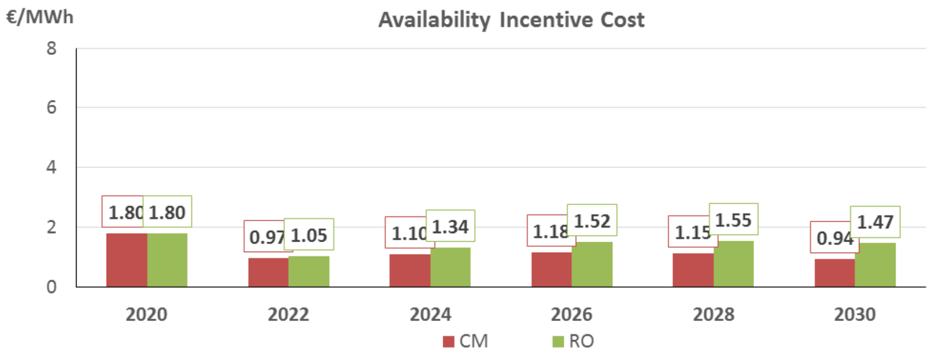

Figure 47. Comparison of the availability incentive costs in the *Low scenario* for the period 2020-2030.

It is also relevant to highlight that this incentive, even if in general terms represents a lower expenditure with respect to the CM or RO cost, when adding up both incentives (CM+AV.INC costs and RO+AV.INC costs) the resulting outcome favours the central buyer model in this regard as seen in Figure 48.

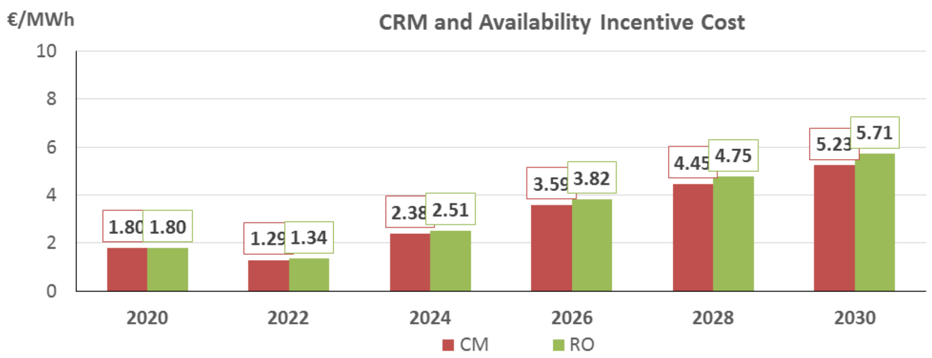

Figure 48. Comparison of the total CRM costs in the *Low scenario* for the period 2020-2030.

Up to this point, it can be concluded that RO favour lower market prices whereas CM leads to lower CRM costs. Let's see then what happens when analysing the total costs in Figure 60.

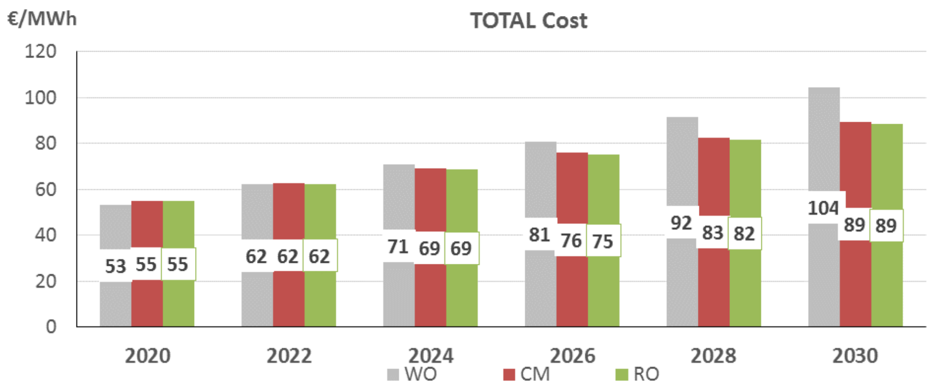

Figure 49. Comparison of the total cost for the system in the *Low scenario* for the period 2020-2030.

The figures release that the total costs for the system in case of implementing a RO is lower. Therefore, it can be affirm that the decreases in energy prices has more weight than the increase in regulated costs.

VI.1.2. **Medium scenario**

The following Figure 50 shows the net capacity that will enter the system each year of the period so as to reach the targeted CI:

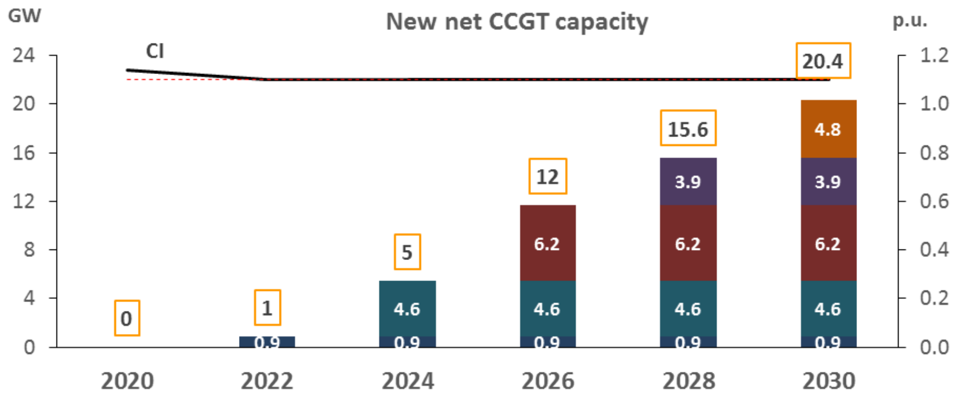

Figure 50. Net CCGT capacity that enters the system with CRM in the *Medium scenario*.

It is observed in this figures that in the *medium scenario* capacity will be entering the system every year since 2022 on reaching a total new installed capacity of 20.4 GW at the end of the period. This means that an auction will take place every year since the first one, which will take place 3 years prior to the first delivery period i.e. the year 2018.

VI.1.2.1. *Alternative 1: CM*

Let's first see, how much would be the benefit of the plants if no incentives were applied taken into account their cost and the only income that is what they get from the market. The results are shown in next Figure 51:

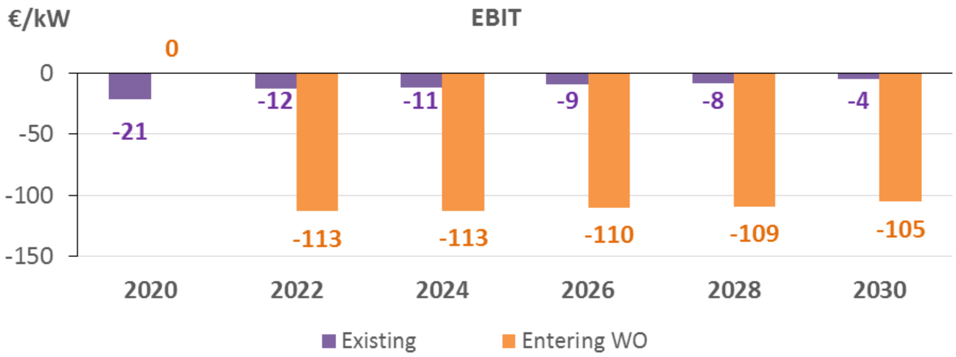

Figure 51. EBIT of CCGT fleet if no incentives applied in the *Medium scenario* with CM.

Following the process as in previous scenarios, the results obtained are those of Figure 52:

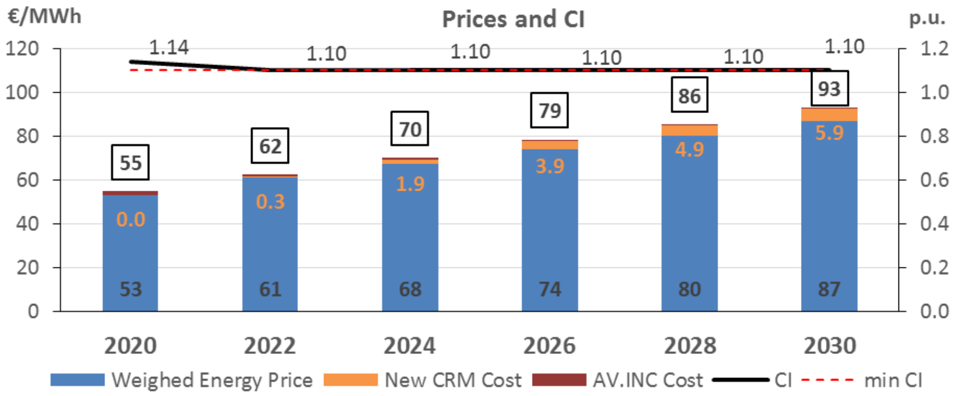

Figure 52. Energy price, CRM cost, AV.INC cost and the CI in the *Medium scenario* with CM.

In this figure it is appreciated the proportion of the CRM cost with respect to the energy price. It is small but more it is the availability incentive cost decreases also along the period due to the increment of energy prices and the subsequent increment of incomes. The CM cost increases along the period due to the increase of entrances since 2020 onwards.

VI.1.2.2. *Alternative 2: RO*

As in the case of a CM, the same process is followed for the RO. Then, let's first see, how much would be the benefit of the plants if no incentives were applied taken into account their cost and the only income that is what they get from the market. The results are shown in nextFigure 53:

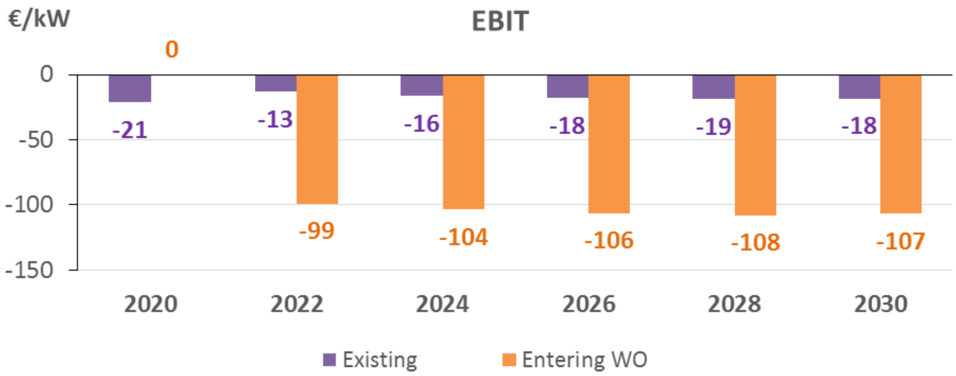

Figure 53. EBIT of CCGT fleet if no incentives applied in the *Medium scenario* with RO.

Following the process explained in V.2.3. the results obtained are those of Figure 54:

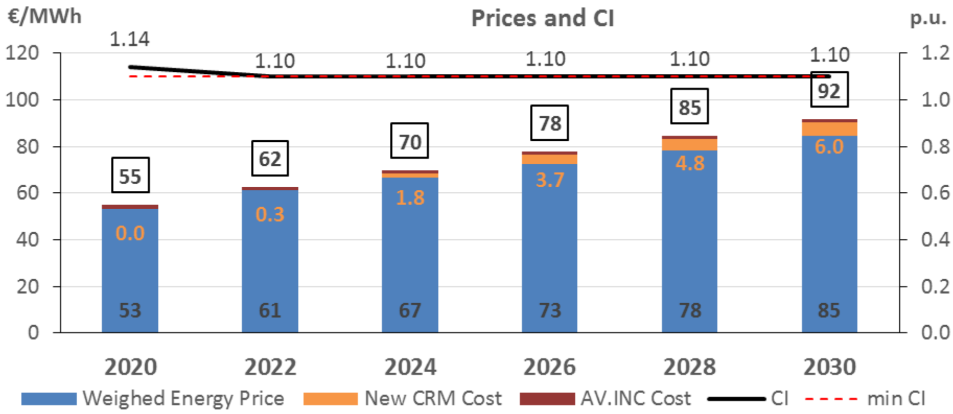

Figure 54. Energy price, CRM cost, AV.INC cost and the CI in the *Medium scenario* with RO.

In a first look, this figure seems to reveal the same conclusions as the corresponding to the CM (see Figure 52): the proportion of the CRM cost with respect to the energy price is small but more it is the availability incentive cost. The RO cost increases along the period due to the increase of entrances since 2020 onwards. On the other hand, the availability incentive does not have a clear tendency.

In the following Figure 55 the load factor of CCGT unit is shown:

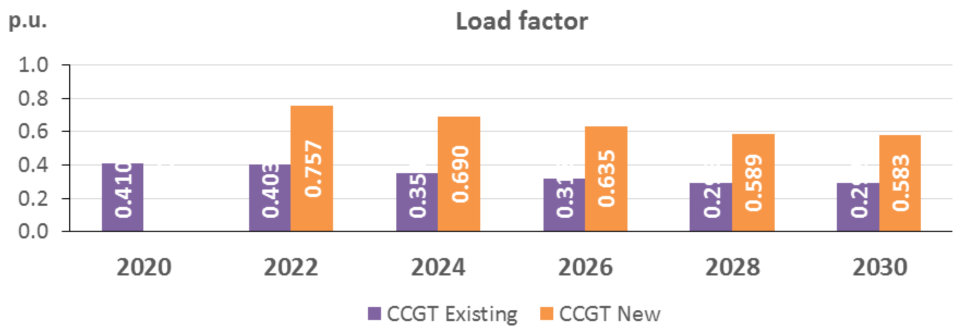

Figure 55. Load factor of CCGT units in the *Medium scenario* with RO..

In this case, it is observed as existing and new units have a much different load factor (in the CM all CCGT units have the same load factor). Despite all units of the same type are equal, holder of RO are dispatch more than existing units due to, in general terms, RO units bid lower than the existing units when the market price is near the strike. Therefore they will work more hours than existing one as Figure 55.

VI.1.2.3. *Comparative analysis of the alternatives*

In this section, an assessment of the two alternative is done. For this aim, it is presented a comparison between them in terms of energy cost for consumers, contribution to the system regulated costs of the mechanisms and cost recovery of generators.

First of all, Figure 56 presents the weighed energy price resulting from the implementation of these mechanism (CM and RO), and it is compared also with the base case scenario where no capacity were in place (WO).

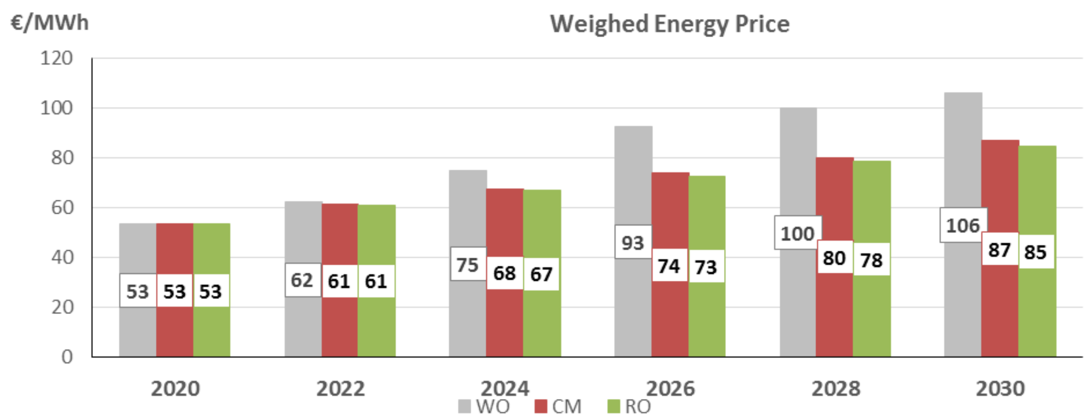

Figure 56. Comparison of the weighed energy price in the *Medium scenario* for the period 2020-2030.

It is observed, as it was expected, that the energy price for consumers would be the highest in the WO case, due to the high costs of the ENS (see previous Figure 29). When comparing the resulting energy price of applying a CM with a RO, it is perceived that the energy price is lower in the case of RO. This difference appears due to the effect of the strike as a price cap in the market price.

With regard to the cost of the mechanism, Figure 57 shows the cost per MWh of energy demanded that the CRM suppose.

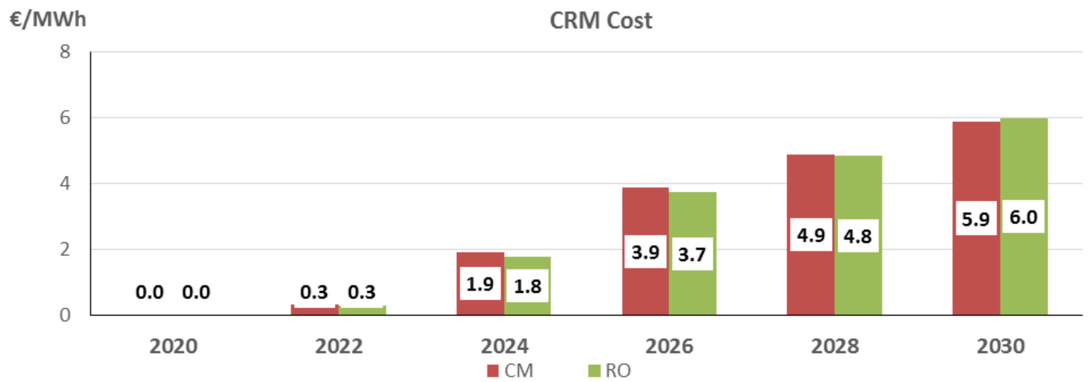

Figure 57. Comparison of the CRM costs in the *Medium scenario* for the period 2020-2030.

It is observed that the RO alternative leads to more economic cost per MWh of energy demanded from 2022 to 2028. However, this is not the case in the year 2030. For understanding this inversions of tendency, we have to pay attention to the evolution of the production of the units under CM and RO and compare it with the evolution of the energy price.

As well as in the low scenario, Figure 56 shows that energy prices are higher when CM mechanism applied. So it could lead to the wrong conclusion that these units are recovering more fixed cost form the market and thus they are asking for less premium to the regulator, but as Figure 57 this is not the case i.e. the cost of the mechanism is higher because they are asking more premium.

CM units are producing less hours than RO units due to the strategic bidding of the CCGT fleet. As the previous Figure 55 shown, in general terms, RO units bid lower than the existing units, therefore they will work more hours than them. In the same way, in the CM mechanism both new and existing units will bid the same under all circumstances so they all will work the same number of hours.

Now then, it can be understand why in the year 2030 CM units ask less than RO units. This is because there is a point of inflexion when the market price increases enough so as to compensate the lower incomes of these units do to the lower production. Therefore, they will as less form the regulator.

With regard to the availability incentive cost, Figure 58 shows as all along the period of study, incentivising the availability of existing plants is more costly for those coexisting with a reliability option mechanism. This is a direct result of the lower prices of energy characteristic of the cap due to the strike price and the subsequent reduction of the incomes of generators.

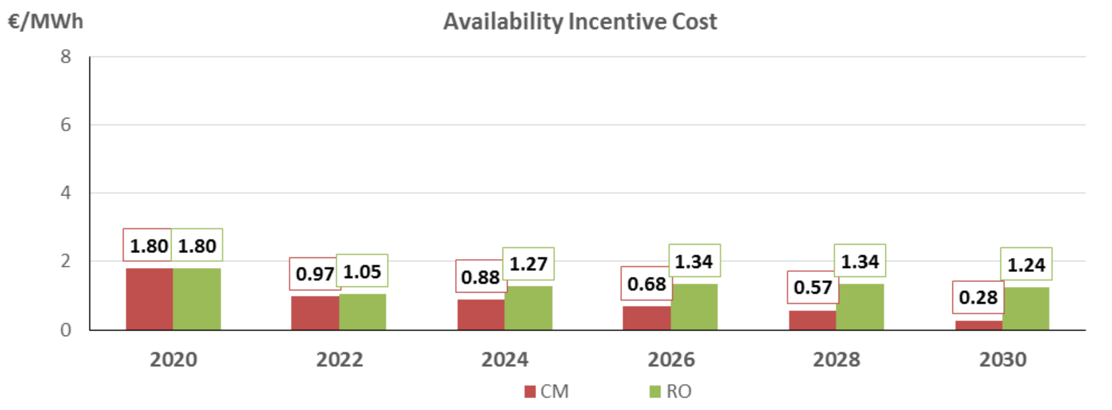

Figure 58. Comparison of the availability incentive costs in the *Medium scenario* for the period 2020-2030.

It is also relevant to highlight that this incentive, even if in general terms represents a lower expenditure with respect to the CM or RO cost, when adding up both incentives (CM+AV.INC costs and RO+AV.INC costs) the resulting outcome favours the central buyer model in this regard as seen in Figure 59.

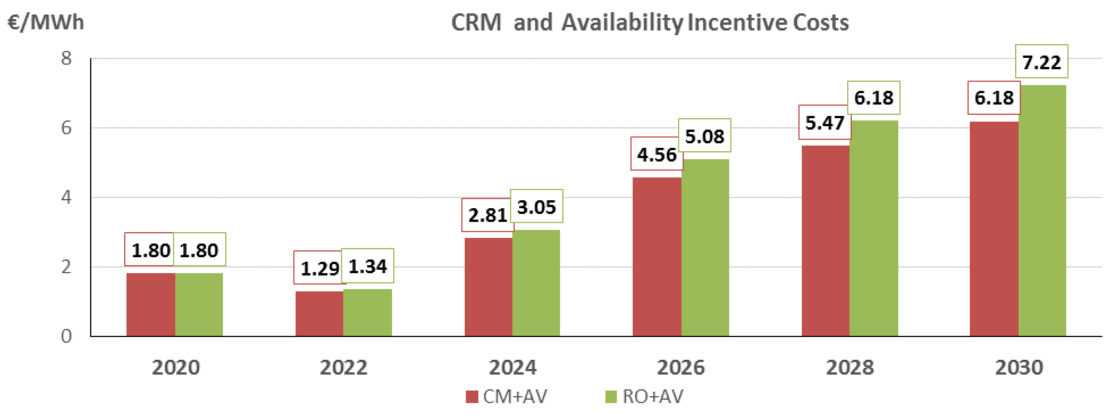

Figure 59. Comparison of the total CRM costs in the *Medium scenario* for the period 2020-2030.

Up to this point, it can be concluded that RO favour lower market prices in the *medium scenario* as well, whereas CM leads to lower CRM costs.

When analysing the total costs in Figure 60.

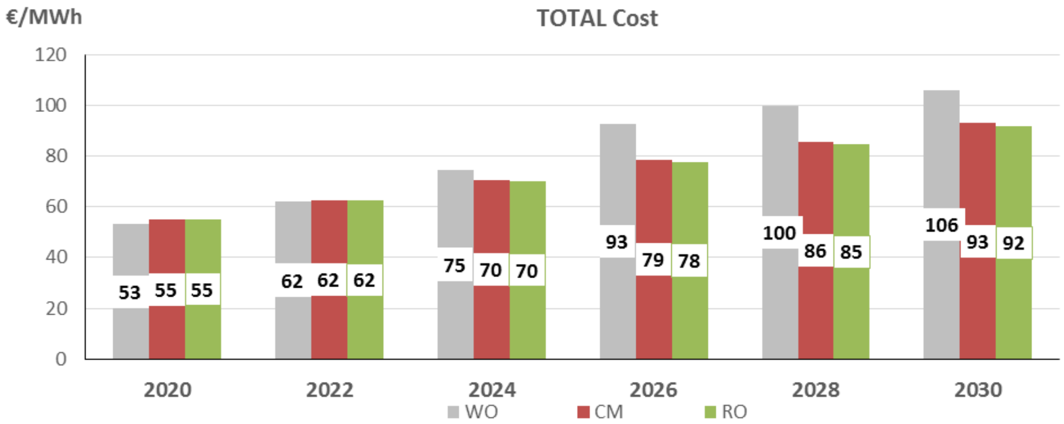

Figure 60. Comparison of the total cost for the system in the *Medium scenario* for the period 2020-2030.

As in the case of the low scenario, the figures release that the total costs for the system in case of implementing a RO is lower. Therefore again, it can be affirm that the decreases in energy prices has more weight than the increase in regulated costs.

VI.1.3. **High scenario**

The following Figure 61 shows the net capacity that will enter the system each year of the period so as to reach the targeted CI:

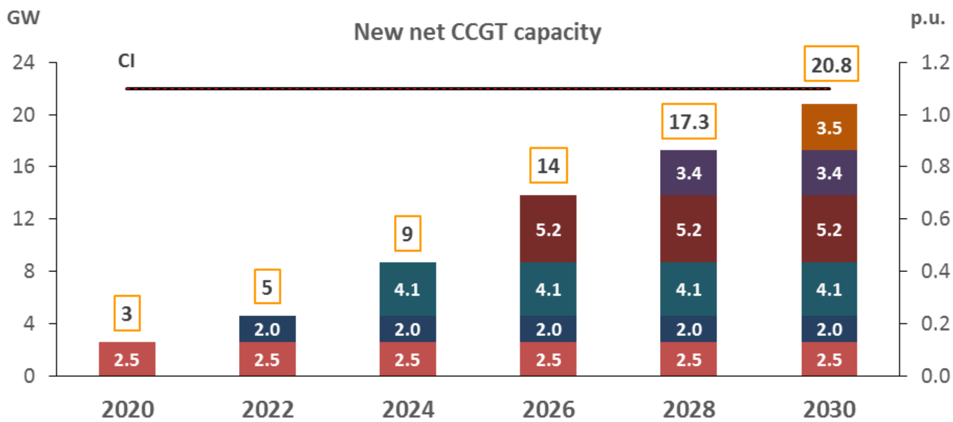

Figure 61. Net CCGT capacity that enters the system with CRM in the *High scenario*.

It is observed in this figures that in the *high scenario* capacity will be entering the system every from the beginning of the period until reaching an accumulated new installed capacity of 20.8 GW at the end of the period. This means that an auction will take place every year since the first one, which should take place 4 years prior to the first delivery period i.e. the year 2016.

The, because of this tight time terms, there is a risk of falling below the 1.1 margin targeted if this scenario actually materializes.

VI.1.3.1. *Alternative 1: CM*

Let's first see, how much would be the benefit of the plants if no incentives were applied taken into account their cost and the only income that is what they get from the market. The results are shown in next Figure 62:

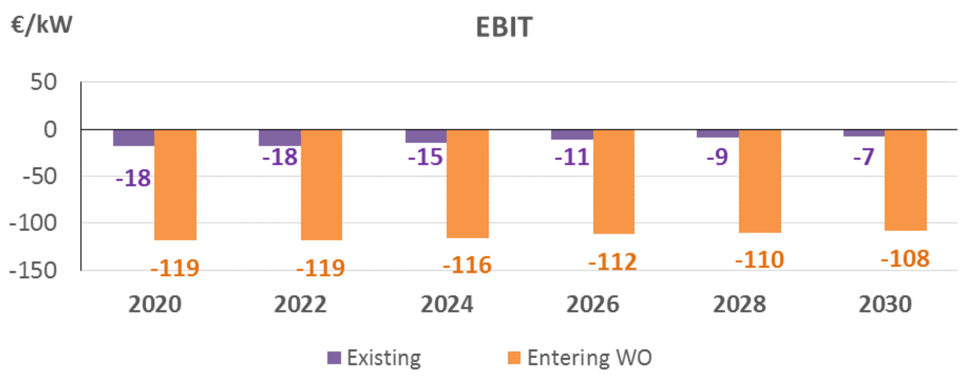

Figure 62. EBIT of CCGT fleet if no incentives applied in the *High scenario* with CM.

Following the process explained before, the results obtained are those of Figure 63:

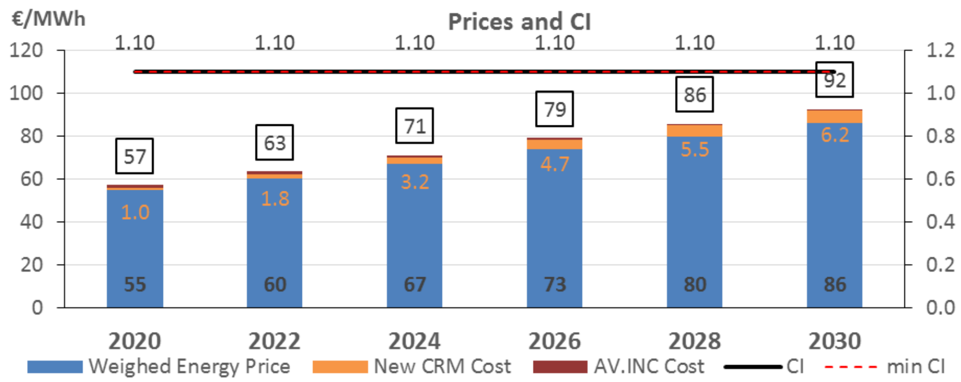

Figure 63. Energy price, CRM cost, AV.INC cost and the CI in the *High scenario* with CM.

In this figure it is appreciated the proportion of the CRM cost with respect to the energy price. It is small but more it is the availability incentive cost decreases also along the period due to the increment of energy prices and the subsequent increment of incomes. The CM cost increases along the period due to the increase of entrances since 2020 onwards.

VI.1.3.2. *Alternative 2: RO*

As in the case of a CM, the same process is followed for the RO. Then, let's first see, how much would be the benefit of the plants if no incentives were applied taken into account their cost and the only income that is what they get from the market. The results are shown in next Figure 64:

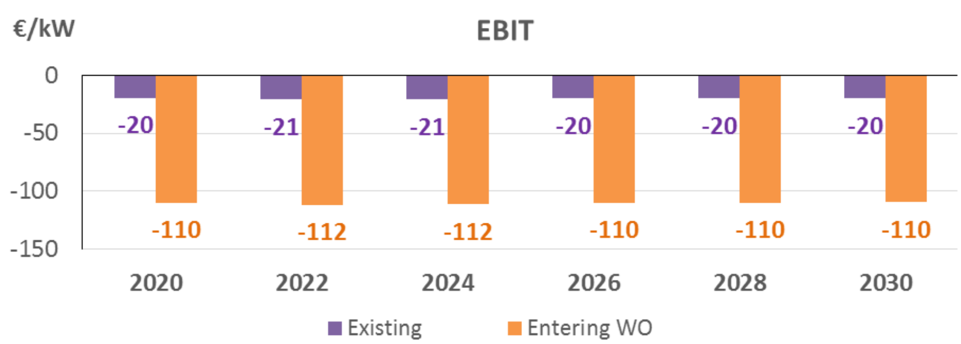

Figure 64. EBIT of CCGT fleet if no incentives applied in the *High scenario* with RO.

Following the process explained before the results obtained are those of Figure 65:

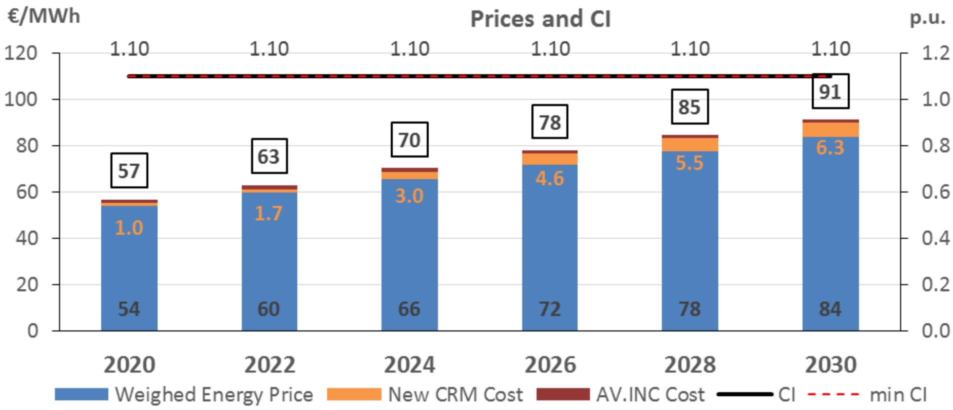

Figure 65. Energy price, CRM cost, AV.INC cost and the CI in the *High scenario* with RO.

In a first look, this figure seems to reveal the same conclusions as the corresponding to the CM (see Figure 63): the proportion of the CRM cost with respect to the energy price is small but more it is the availability incentive cost. The RO cost increases along the period due to the increase of entrances since 2020 onwards. On the other hand, the availability incentive does not have a clear tendency.

In the following Figure 66 the load factor of CCGT unit is shown:

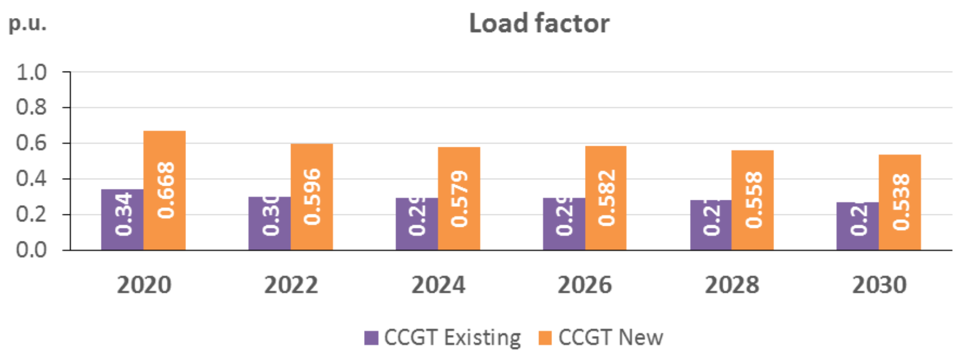

Figure 66. Load factor of CCGT units in the *High scenario* with RO.

In this case, it is observed as existing and new units have a much different load factor (in the CM all CCGT units have the same load factor). Despite all units of the same type are equal, holder of RO are dispatch more than existing units due to, in general terms, RO units bid lower than the existing units when the market price is near the strike. Therefore they will work more hours than existing one as Figure 66.

VI.1.3.3. *Comparative analysis of the alternatives*

In this section, the assessment of the two alternative under the *high scenario* is done. For this aim, following the same procedure as in the previous scenarios, it is presented a comparison between them in terms of energy cost for consumers, contribution to the system regulated costs of the mechanisms and cost recovery of generators.

First of all, Figure 67 presents the weighed energy price resulting from the implementation of these mechanism (CM and RO), and it is compared also with the base case scenario where no capacity were in place (WO).

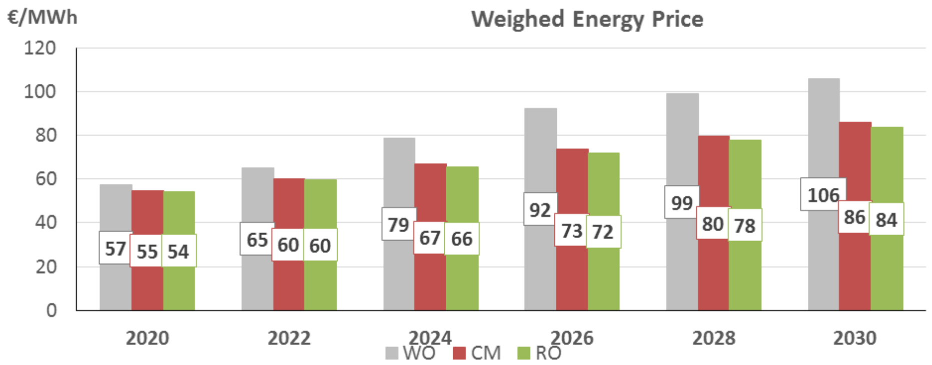

Figure 67. Comparison of the weighed energy price in the *High scenario* for the period 2020-2030.

As in the previous scenarios, t is observed that the energy price for consumers would be the highest in the WO case, due to the high costs of the ENS. When comparing the resulting energy price of applying a CM with a RO, it is perceived that the energy price is lower in the case of RO. This difference appears due to the effect of the strike as a price cap in the market price.

With regard to the cost of the mechanism, Figure 68 shows the cost per MWh of energy demanded that the CRM suppose.

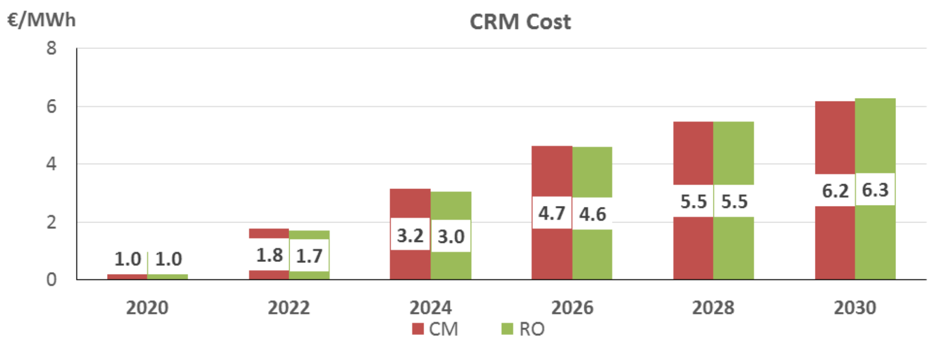

Figure 68. Comparison of the CRM costs in the *High scenario* for the period 2020-2030.

It is observed that the RO alternative leads to more economic cost per MWh of energy demanded from 2022 to 2028. However, this is not the case in the year 2030. As explained in the previous VI.1.2.3. , units are recovering less cost form the market price and asking more premium, because they are producing less hours the RO-holder units. This occurs due to CM contract-holders bid higher that RO. In the same way, the year 2030 the tendency changes due to the fact that there is a point of inflexion where the market price increases enough so as to compensate the lower incomes of these units do to the lower production.

With regard to the availability incentive cost, Figure 58 shows as all along the period of study, incentivising the availability of existing plants is more costly for those coexisting with a reliability option mechanism. As explained in the low and medium scenario analysis, this is a direct result of the lower prices of energy characteristic of the cap due to the strike price and the subsequent reduction of the incomes of generators.

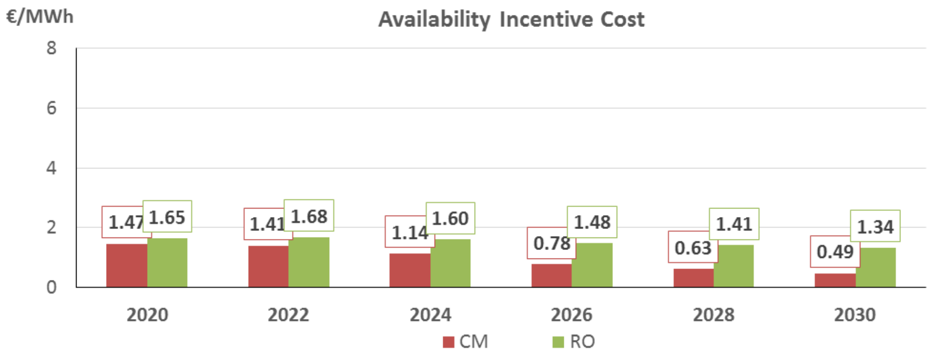

Figure 69. Comparison of the availability incentive costs in the *High scenario* for the period 2020-2030.

Nevertheless, when adding up both incentives the resulting outcome favours the central buyer model in this regard as seen in Figure 70.

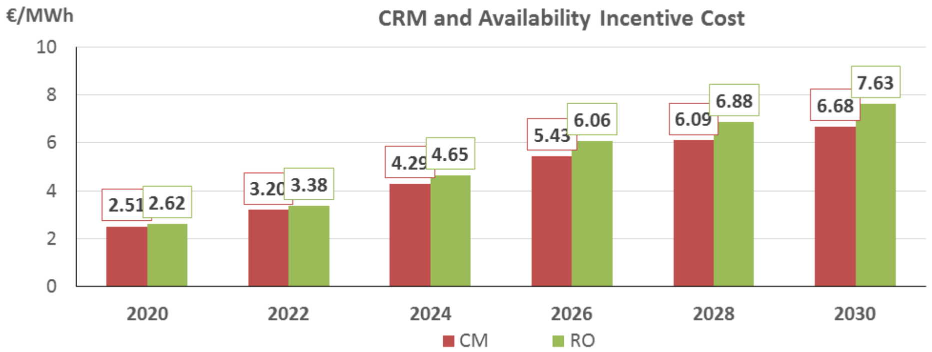

Figure 70. Comparison of the total CRM costs in the *High scenario* for the period 2020-2030.

Up to this point, it can be concluded that RO favour lower market prices whereas CM leads to lower CRM costs. Let's see then what happens when analysing the total costs in Figure 71.

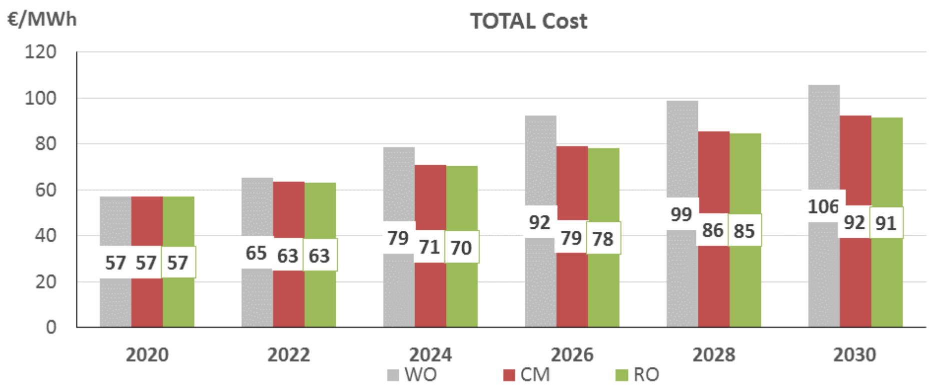

Figure 71. Comparison of the total cost for the system in the *High scenario* for the period 2020-2030.

Once again for the *high scenario*, the figures release that the total costs for the system in case of implementing a RO is lower because the decreases in energy prices has more weight than the increase in regulated costs.

VI.2. SENSITIVITIES TO THE MEDIUM SCENARIO

Once we have studied how the CRM proposed perform in the three scenarios, some sensitivities are carried out in this section so as to support the conclusions released if the assumptions initially made differ from the reality or, on the contrary, to detect possible breaches in the conclusions or specific situations that may lead to weaker outcomes. In this way, the robustness of the alternatives can be better quantified.

For this sensitivities, the *medium scenario* has been selected as the base case against which the changes measured are going to be compared.

VI.2.1. Demand increases by 1.8 % each year until 2030

From the safe side, we assumed in V.1.1. , that the demand growth rate was 2.3% as foreseen in worst case scenario of (MINETUR, 2015). In that report, other two scenarios are considered with lower values of demand rate increase. For this reason, a value between them is been considered and simulated.

The same process as the one describe in section V.1.2. is followed to determine the base case *medium scenario* with a demand rate increment of 1.8%.

<u>Lower capacity entering the system</u>

In this scenario of lower demand, the capacity that should be incentivise so as to reach the 1.1 will be a 17% lower with regard to the base case. New CCGT would enter the system with a capacity of 44,669 GW.

<u>Lower energy prices</u>

Also the energy prices will be reduced in the case of 1.8% demand rate increase, in a proportion very similar independently of the mechanism in place as Figure 72.

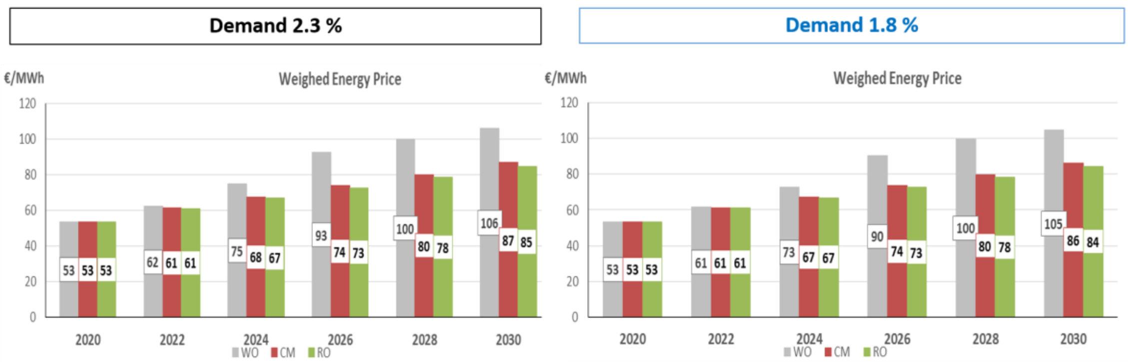

Figure 72. Comparison of the weighed energy price in the *Medium scenario*. Base case: 2.3% demand increment rate - Sentitivity: 1.8% demand increment rate.

<u>Lower regulated costs for consumers</u>

With regard to the cost of the CRM and availability incentives, it is observed in Figure 73 that they will be reduce if the demand if lower. The RO mechanism will continue to be more expensive than the CM, because capacity providers internalize the implicit penalty of the mechanism within their bids in the capacity auction.

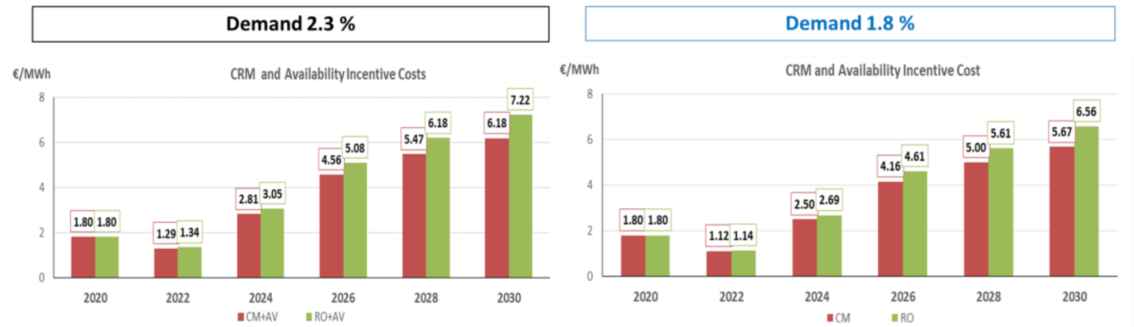

Figure 73. Comparison of the total CRM costs in the *Medium scenario*. Base case: 2.3% demand increment rate - Sentitivity: 1.8% demand increment rate.

<u>Lower total cost for the system</u>

With regard to the total cost, it is observed in Figure 74 that they will be reduce if the demand rate increase is 1.8%. The RO mechanism will continue to be the most economic option under this scenario.

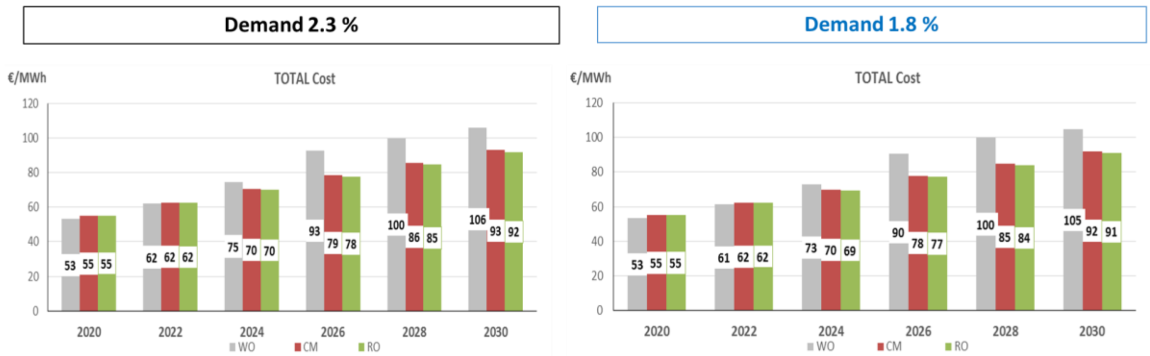

Figure 74. Comparison of the total costs in the *Medium scenario*. Base case: 2.3% demand increment rate - Sentitivity: 1.8% demand increment rate.

VI.2.2. **Variation in the strategic bidding of agents**

This sensitivity consists on changing the strategic bidding parameter of agents. It was stablished that the maximum value of the parameter α was 60%. Then, in this section is going to be studied the effect of agents bidding at a 20% over their variable cost and, on the contrary, if they bid a 100% over their variable costs. Figure 75 shows these the three cases graphically.

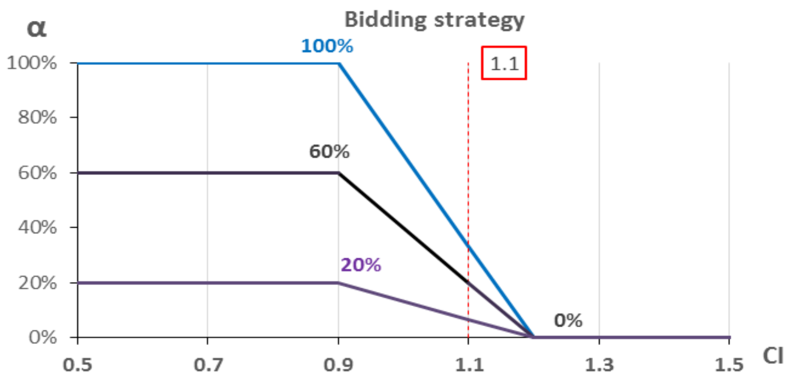

Figure 75. Bidding strategy of agents represented through the parameter α in for the sensitivities studied.

<u>Energy prices increase along with the strategic parameter</u>

InFigure 76 it is represented the variation of the energy price along with the parameter α. In the case of agents bidding at a maximum of 100% over their variable costs, energy prices are higher than in the base case (60%) and it is appreciated as markets with RO contracts contain more the price increment than CM contract in a considerable amount.

If, on the contrary, agents bid at a maximum of a 20% over their variable cost both mechanisms tend to release the same market price[25]. This occurs because, as it is seen in Figure 75, when the CI is 1.1 (as it is the case) their maximum bid is lower than the 10%, which is exactly the where the strike price is set. Therefore, agents bids never overpass the strike and so they do not have to pay an implicit penalty.

Figure 76. Comparison of the weighed energy price in the *Medium scenario*. Base case: α_{max}=60% - Sentitivities: α_{max}=20% and α_{max}=100%

<u>The higher the strategic parameter, the lower the costs of the CRMs</u>

It is observed in Figure 77 as it was expected, that the higher the strategic parameter, the lower the costs of the CRMs, because they are able to recover a greater proportion of their fixed cost from the market price. Then, the results of sensitives to α on the costs of the mechanism are the opposite then as those observed inFigure 76 with prices.

[25] In a market with perfect competence market agents would bid with a null parameter α.

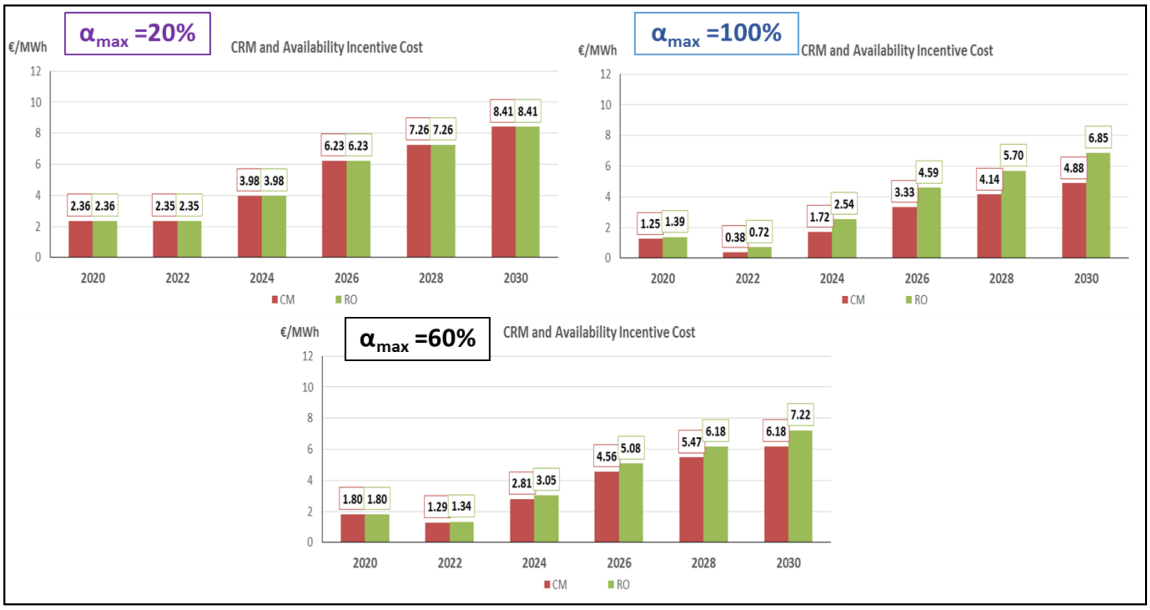

Figure 77. Comparison of the total CRM costs in the *Medium scenario*. Base case: α_{max}=60% - Sentitivities: α_{max}=20% and α_{max}=100%

<u>The higher the strategic parameter, the higher the costs for the system in CM and stable in RO</u>

In Figure 78 it is observed as in the case of CM, the total costs for the system rise, if market agents bid higher. Therefore, it is concluded that the impact of a higher strategic parameter on the increment in the energy price prevails with regard to the decrease in the regulated costs. On the other hand, we can affirm that RO mechanism is able to keep the total costs stable (~92€/MWh in 2030) when agents bids are higher.

Once again, the impact of both mechanism on the total costs is equal as long as the market move to the perfect competence.

Figure 78. Comparison of the total costs in the *Medium scenario*. Base case: α_{max}=60% - Sentitivities: α_{max}=20% and α_{max}=100%.

CHAPTER VII: **Conclusions**

VII.1. CONCLUSIONS

In the discussion about whether or not the energy-only is able to guarantee security of the electricity systems, we conclude that there is a market failure that should be addressed through the implementation of a CRM (i.e. regulated payment) that allows marginal units to recover their fixed costs that they cannot recover from pure energy market income The basic principles to consider when implementing a CRM are:

- Be necessary, that is to say, a deep analysis needs to be conducted for identifying and specifying the SoS issue that is consider to be addressed.
- Be appropriate, which refers to the requirement of analysing potential alternative measures before determining the appropriate proceeding (which may even not be the implementation a CRM)
- Be proportional, i.e. the amount of aid should be the minimum necessary to address the issue and achieve the objectives aimed. In other words, the implementation of the CRM should not increase system and consumers' costs.

Avoid negative effects on competition and trade by minimizing potential distortions to the market. Transparency and non-discrimination should be guaranteed.
The type and design of a CRM varies widely depending on the specific issue that it intends to address. However, there is a proper choice and an appropriate design depending on the specific adequacy issue that has to be faced and depending also on the characteristic of the specific power systems.

Therefore, for reaching the objectives aimed, each type of mechanism should be considered. For instance, strategic reserves seem to be more useful to address temporary and locational firmness issues, by preventing mothballing and closure of plants. Conversely, capacity markets may address in a proper way a long term adequacy concern.

With regard to the design variables, it has been demonstrated that they require a special attention so as to achieve cost-efficient results that directly address the specific SoS problem and the specific characteristics of each power system. In this line, to foster competitiveness is revealed as a key objective of any decision made when designing the mechanisms.

In general terms, eligibility criteria should avoid explicit exclusion of capacity providers. Using specific requirement such as size or technology performance evaluated in a pre-qualification process may prevent from unfair exclusion of some types of technologies. If possible, any type of capacity should be able to participate in the mechanism so as to foster competition and avoid the necessity of further interventions, which would affect the natural equilibrium of the generation fleet.

With regard to the allocation process, it seems to be a general agreement in favour of competitive allocation processes, given that, if well designed, they reveal the true value of the capacity at any time. Thus it avoids over- or under-compensation and therefore over- or under-procurement. An administrative procedure to select the capacity provider as well as their remuneration should be avoided. Only a likely risk of market power abuse could make this option justifiable. However, first of all, it has to be considered that the competitive processes can include certain characteristics (price caps and floors in auctions, definition of price takers/makers) that can also minimize the risk of market power abuse.

The proper design of these two variables is useless if the capacity product has not been well defined, this implies the clear definition of the obligation of the holder of the capacity agreement and the penalties that they face if their commitments are not met. Many of the international experiences studied in Annex C have shown that a flawed design of the capacity product leads to inefficient results.

Again, obligations vary depending on the specific problem that is addressed and the specific market. The lead time and the contract duration are paramount so as to bring to the system the required type of capacity by minimizing risk for capacity providers. For instance, new built plants will need longer lead time and longer contract durations that existing plants. Also demand side response and distributed storage will need shorter lead time so as to face future uncertainty.

The design of penalties is essential in order to incentivise capacity providers to meet their obligations. They should not be too low for guaranteeing the objective of supply but not too high either, because providers may not be willing to participate in the mechanism if the risk of not meeting their obligation is excessive.

In conclusion, before implementing a CRM the specific SoS that is been addressed and the specific characteristics of the power system should be identified so as to choose which alternative better fits and define the designing variables that will lead to an efficient result. There is not a unique optimal mechanism but a best choice and design for each particular case.

With regard to specific SoS problem in the Spanish power system, after studying the experience of the Spanish power sector with CRM as well as the assessment made of the current situation and future expectations, it can be concluded that something has to be done. A CRM is still needed, however, the current design of the CRM may not attract sufficient investments in new generation capacity when needed and is implying very high costs to the system.

Additionally, as per the design and performance, European authorities are not valuing positively the current Spanish CRM. According to EC's analysis, because of being too selective and not perfectly designed Spanish CRM has led to an inefficient outcome.

All of the above calls for the need of a systematic approach in the design of a future CRM to be incorporated to the Spanish regulation that:

- Succeeds to attract the required amount of investment in the relevant timeframe.
- Is compliant with the regulatory and economic principles in the design of CRM.
- Follows the recommendations of the Spanish Regulator and EC guidelines.

In sum, is efficient in terms of costs for the system with regard to the utility provided and able to keep the reliability standards in safe levels.

In this line, from the evaluation of the necessity of a CRM for the period of study under three different plausible scenarios, it can be concluded **that Spain needs a CRM** so as to guarantee SoS in the medium and long term. It has to succeed in fostering availability of plants and in bringing new investment into the system so as to achieve the reference value of 1.1 for the coverage index.

With the purpose of facing the specific SoS issue of the Spanish power sector, it has been concluded that capacity markets based on a central auction or one with reliability option contract may tackle this issue in a cost-efficient manner. And this has been demonstrated with the simulations carried out under the three scenarios, the main outcome of which for year 2030 are shown in Table 26:

Table 26. Main results obtained from the simulations of the CRMs in the three scenarios for the year 2030.

			Low scenario	***Medium scenario***	***High scenario***
	New net CCGT capacity	[GW]	13.56	20.36	20.78
CM	Weighed energy price	[€/MWh]	84.2	86.7	85.7
	Cost of the mechanism	[€/MWh]	5.2	6.2	6.7
	Total costs for consumers	[€/MWh]	89.5	92.9	92.4
	Premium	[€/kW]	122.5	112.1	115.4
RO	Weighed energy price	[€/MWh]	82.8	84.5	83.7
	Cost of the mechanism	[€/MWh]	5.7	7.2	7.6
	Total costs for consumers	[€/MWh]	88.5	91.8	91.3
	Premium	[€/kW]	120.9	113.7	116.9

The table shows that the **capacity requirement could vary widely depending on the scenario**, from 13.6 GW of capacity in the low scenario to a maximum requirement if 20.8 GW in a scenario with increased phase-out of current thermal facilities and higher penetration of RES. In any case, it can be concluded that this intervention complies with the **necessity principle** stablished by the EC state aid guidelines.

In this line, energy prices will depend on the evolution the mix and with this, also the weighed cost of the mechanisms. This latter increases with the requirements of the market in terms of new capacity, both in the CM alternative and the RO. Nevertheless, even if the high scenario requires more capacity to be installed so as to meet the 1.1 targeted, the **price in the third scenario is lower** with respect to the medium owing to the lower variable cost of the relevant amount of **RES technologies** that penetrate in this scenario.

It is concluded also that the energy price for consumers would be the highest in a scenario without any CRM due to the high costs of the ENS and the likely existence of strategic bidding carried out by generators when the capacity margins of the system are tight. The intervention would fulfil with the **proportionality principle** required by the EC guideline, which stablishes that the implementation of a CRM should not increase system and consumers' costs.

When comparing the resulting energy price of applying a CM with a RO, it is perceived that the energy price is lower in the case of RO. This difference appears due to the effect of the strike as a **price cap** in the market price.

Then two cases may arise depending on the weight of the load factor with regard to the energy price. It may happen that:

1. Higher energy prices lead to CM cost being higher than RO cost and
2. Higher energy prices lead to RO cost being higher than CM cost.

In the first situation, despite this fact, CM units are recovering more fixed cost form the market per unit of energy sold and thus they should be asking for lower premiums to the regulator, this is not the case because CM units are producing less hours than RO units due to the strategic bidding of the CCGT fleet outside the RO scheme.

In general terms, RO units bid lower than the existing units, therefore they will be running more hours than them. In the same way, in the CM mechanism both new and existing units will bid the same under all circumstances so they all will work the same number of hours.

The second case refers to CM units asking less premium than RO units. This occurs because there is a point of inflexion when the market price increases enough so as to offset the effect of a reduced load factor. Therefore, they will ask for lower premiums.

In this line, and after the sensitivities carried out, it can be affirmed that RO mechanism can keep the costs for consumers more stable when changes with regard to the in the projected scenarios arise. This is then a powerful tool or the regulator so as to face the future uncertainty of the Spanish power system without putting a burden into the system costs.

It is observed that much more capacity is requiring a CRM and the premium required is higher if compared with the values stablished by the different regulations on CRM of the Spanish electricity sector in the last decade for the investment incentive. Nevertheless, the cost of the mechanisms in energy terms is comparable to the historical ones.

With regard to the design of the availability incentive, it can be said that its design is adequate so as to foster availability of existing plants without incurring in high cost. It guarantees that providers of capacity will receive a reasonable return from their activities.

In conclusion, it can be said that the Spanish power system has a systemic SoS problem that can be addressed by implementing either a central buyer model or a reliability option mechanism. They both succeed in sending the right economic signals so as to bring the capacity needed into the system. In this way, the required level of security of supply is achieved in a cost-efficient way. At this point, the regulator will have to weigh up if it chooses to keep system regulated costs down by selecting a capacity market based on a central auction, or on the contrary, to incur in higher regulated cost to keep energy prices down and stable with a flexible RO mechanism.

VII.2. LIMITATIONS AND FUTURE LINES OF RESEARCH

During the development of this master's thesis some limitations have arisen that should be considered, but at the same they could be seen as potential future lines of research so as to complement or deepen this study.

<u>Allowing cross-border participation</u>

One of these topics is the XB participation in national CRM. Beside MS are not allow to discriminate between XB contracts and national contracts when taking safeguard measures or resolving congestions, the EC's sector inquiry on capacity mechanism (European Commission, 2016a) showed that XB participation is not enable in most of the individual CRM, which leads to an emerging risk of increasing fragmentation of IEM.

Also, in this study the participation of interconnectors and cross border capacity provider have not been considered in the simulations in order to assess the preferable CRM.

Nevertheless, as it has been stated (see Figure 19), the particular situation of the Spanish power system and the future expectation on levels of interconnected capacity, let us some margin to include foreign participation in the mechanisms proposed. Moreover, other European countries are recently including in their CRM designs the possibility of counting on their neighbours' contribution for SoS (German strategic reserves mechanism and UK capacity market between others), and we can learn from their experiences before implementing this characteristic on the Spanish CRM.

Demand side participation and storage

When assessing the capacity that has to enter the system so as to reach a certain level of SoS, demand side response and storage providers plays a key role in reducing them. In this study, it has been considered that their participation was not varying the outcomes of the assessment of the CRM proposed, given that the only influence was the reduction of the system peak demand and thus the decrease in the requirement of provision of generating capacity. Both design definitions (central buyer model and reliability options) contemplated their participation even if afterwards it has not been simulated.

However, this assumption is justifiable if large consumers as those participating in the interruptibility scheme are only considered. That the only effect of demand response participation is the reduction of the capacity requirements could be not strictly true in all situations. When talking about demand response when takes the form of households or smaller consumers that react to prices in an elastic way, the impacts could be others. In this vein, when moving towards a more 'smart' system which counts on smart grids, prosumer and aggregators as a way of achieving a solid security of supply, the possible effects of demand response and storage participations are proposed to be studied.

Penalties

It has been considered that capacity providers are providing energy to the system always when required. That is to say, that they are always available (availability factor equal to 1) when needed so no penalties applied. It has been considered then that capacity providers put all their net capacity to meet the system needs without risk of unplanned outages.

However, the eventual effectiveness of the CRM is highly dependent on the penalties design. It could be a future line of research whether and/or how penalties design affect the assessment made in this study.

Same remuneration for existing and new plants

With regard to the remuneration of existing and new plants, it was a constant point of discussion during the development of this study whether to design a mechanism so as to remunerate at the same levels all capacity providers participating in the capacity auction. Nevertheless, the outcome of that analysis ended up remunerating in excess the availability of existing plants, with the consequent burden to the system regulated costs. Other reason was the UK experience that did not success in attracting all the new capacity required.

For this reason, it was decided to remunerate separately (and differently) to both plants, in a way that tried to be implicit, i.e. by celebrating an auction the year T-1 whose lead time implicitly excludes new plants. In this vein, it is considered to be interesting to study mechanism designs that do not discriminate between any kinds of capacity and, to what extent this is economically justifiable.

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Annexes

Annex A. **List of figures**

Annex B. **List of tables**

Annex C. **International experiences study**

C.1. Central buyer model – UK

C.1.1. General description

The mechanism consist in a capacity market where an auction is organized centrally. The auction is opened to existing and new generators, demand side response (DSR) operators, storage operators and interconnectors (this last since the second auction held in December 2015). Participants that will get an agreement in the auction with a successful bid are awarded with a steady payment during the duration of the capacity agreement in return of a commitment to deliver electricity at times of system stress, which are defined ex ante by the System Operator (National Grid). In case of not completion of the obligations of delivery the energy contracted, penalties apply. The following Figure 79 represent in as simplified manner how this mechanism work.

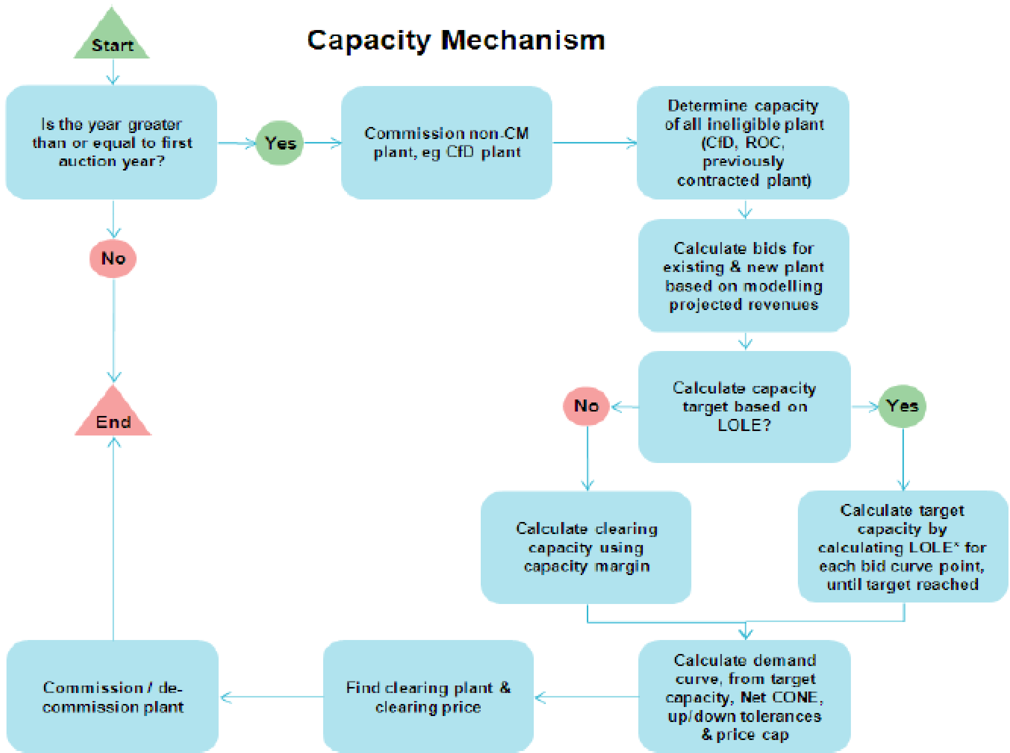

Figure 79. UK capacity market flowchart. Source: (National Grid, 2015b).

C.1.2. Necessity

The UK concerns about SoS arise from the increment in RES penetration and closure of thermal plants owing to its end of operational life and the tight environmental requirements imposed by the carbon tax.The previous energy-only-market structure was not enough for generators to recover their operating cost. In words of Ofgem: '*The "energy-only" market has not yet brought forward sufficient investment in new conventional generation to prevent margins from tightening*' (Ofgem, 2015). For this reason the CRM aims at helping to counter the effects of the "missing money" problem and guaranteeing the SoS.

C.1.3. Design characteristics

<u>Eligibility</u>

The Capacity Market (CM) is technology neutral, which means that all forms of capacity are eligible to participate, including existing and new generation capacity, storage, DSR and interconnected capacity.[26]The exception to participate applied to capacity that receives support from other measures e.g. RES subsidies.

Participation in the CM is not mandatory, although it is the participation in the pre-qualification process for all licenced and eligible capacity, even if they do not intend to participate afterward in the capacity market auction. The purpose of the pre-qualification is to ensure participants in the auction can deliver the capacity they are bidding for. In this way, the System Operator is able to adjust the amount of capacity that is being auctioned based on the volume of capacity opting out of the auction (DECC, 2013).

The pre-qualification generic and specific requirements vary depending on the type of capacity provider (existing or prospective generating unit, or a DSR unit). The generic requirements include basic administrative details such us contact details, licence status, corporate structure or location. Specific requirements for existing generation units is the demonstration of their historic performance, whereas prospective units have to provide evidence of planning consent and connection agreement, a detailed construction plan and details of their expected capital expenditure relative to the duration of the capacity agreement being sought. Credit support is also required as indication of their commitment to participate in the auction and have the plant ready to meet its obligations on time (European Commission, 2014b).

Participation in the CM is not mandatory, although it is the participation in the pre-qualification process for all licenced and eligible capacity. The purpose of the pre-qualification is to ensure participants in the auction can deliver the capacity they are bidding for and allow the SO to adjust the amount of capacity that is being auctioned (DECC, 2013).

The pre-qualification requirements vary depending on the type of capacity provider. Specific requirements for existing generation units is for instance the demonstration of their historic performance. Prospective units' requirements aim at assuring that the plant will be ready on time. For instance, they have to provide evidence of planning consent and connection agreement and credit among other requisites (European Commission, 2014b).

<u>Allocation</u>

National Grid (NG) does an annual SoS analysis and recommends the amount of capacity required to meet the reliability standard[27] to the Government. The Department of Energy & Climate Change (DECC) assesses whether a capacity auction is needed and if it is, a capacity demand curve is determined in advance of capacity auctions, i.e. 4.5 years ahead of the delivery year. This demand curve intends to gives flexibility on the amount of capacity to contract depending on the cost. This curve reflects: (i) the targeted capacity level, (ii) the net cost of new entry (net-CONE)[28], which sets the price at which the target level of capacity would be auctioned, and (iii) the price cap in the auction which is set at the level of GBP

[26] In the first auction of the capacity held in December 2014, interconnector were not allow to participate but in the second auction that took place in December 2015 interconnectors were admitted and were secured 4.2 GW of capacity agreements, corresponding to approximately 9% of the total auctioned capacity (EC, 2016b).

[27] The reliability standard for the GB electricity market is equal to a loss of load expectation of 3 hours/year. This translates as a system security level of 99.97% (European Commission, 2014b).

[28]Net-CONE is determined from the cost of a new build CCGT plant (i.e. gross-CONE) minus expected electricity market and ancillary service revenue (DECC, 2014).

75/kW[29] in order to avoid market power (European Commission, 2014b). The target capacity has a flexibility of ±1.5 GW[30]. This value represents the de-rated capacity of approximately two large CCGT plant and intends to limit the ability of a single plant to influence the auction clearing price (DECC, 2014). There is also a price cap for 'price takers' in £25/kW (50% of net-CONE) also for mitigating market power when there is little competition of new entrants (DECC, 2015) (DECC, 2015).

An example of this curve is shown in Figure 80:

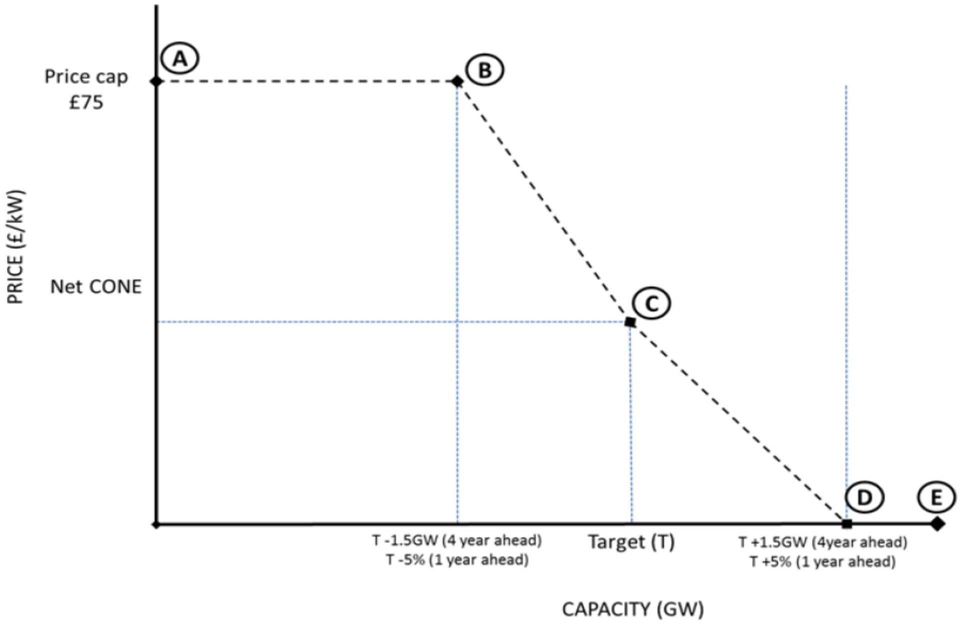

Figure 80. Illustrative capacity demand curve. Source: (DECC, 2014).

Then, eligible capacity providers participate in a competitive central descending-clock, pay-as-clear auctions run by the System Operator. There are an initial auction four years ahead of delivery period, where the successful bidders are awarded a 'capacity agreement' and a year-ahead auction, where the holders of capacity agreements can hedge their positions and ensures the right amount of capacity is procured when more accurate demand forecasts are available. This secondary auction is important for enabling DSR capacity to actively participate in the mechanism.

To mitigate market power, bidders are classified as 'price takers' (who cannot set the price) or 'price makers' (who can). New entrants and DSR resources are classified as price makers, and are free to bid up to the overall auction price cap.

In order to manage their risk, providers can trade their obligations both physically (between the year-ahead auction till the delivery period) and financially (at any point from the four year ahead auction till the delivery period) in a secondary market.

<u>Product definition</u>

[29] The level of GBP 75/kW is set administratively by the Government above a modelled clearing price in the auction under a several likely scenarios, trying to be not so high to avoid market power if there is limited new build participation. It also acts to ensure that new build cannot seek to recover all its fixed costs in its auction bid and leave some revenues for the spot market (European Commission, 2014b).

[30] In case of the T-1 auction the flexibility is of 5% of the target capacity auctioned (DECC, 2014).

Holders of 'Capacity agreements', are provided a steady payment for capacity in return for a commitment to deliver energy when required in the delivery year, or face a penalty linked to the VoLL. The remuneration consists of payments (at the auction clearing price) proportional to their de-rating factor[31] multiplied by their connection capacity (volume which their physical grid connection permits them to export onto the system). One of the purposes of the penalty regime is to fine tune the level of payments from this estimated performance level to the actual performance level of individual plants.

The delivery period is announced with a Capacity Market warning, based on a pre-determined methodology. The warning is published when the triggering criteria has been met or where load is starting to be shed (DECC, 2014).

Agreements are available for different lengths for the different types of participant. New generators ('New Build') can qualify for agreements of a maximum of 15 years. Generators who invest to renovate or restore an existing asset ('Refurbishing') can qualify for agreement of up to 3 years. Current generators ('Existing') and DSR ('Proven and Unproven DSR') are eligible for 1 year agreements (Ofgem, 2015).

C.1.4. Design issues

On the 19th December 2014 National Grid and the DECC announced the results of the first Capacity Market auction. The lower than anticipated clearing price (£19.40 per kW) for capacity delivery in winter 2018/19 was good news for consumers. However, 10GW of generators were not allocated and, as a result, in 2015 around 5MW out of them announced its intention to close (Economics, 2015) (National Grid, 2015a).

In the second auction, held in December 2015, the resulting price of £18.00 kW (National Grid, 2015a) was broadly in line with market expectations. However, 5.1 GW of older existing capacity (2GW CCGT and 3.1 GW coal plants) (Economics, 2015) was unsuccessful in getting capacity agreements. Then, it is foreseeable that without capacity payments, the economics of these older plants is unviable, in the absence of other regulatory support and the UK is facing the risk of losing a total of 10GW of capacity. This would send the system reserve margin deep into negative territory. Given the little success of both auctions in bringing new capacity, particularly gas plants, DECC launched a consultation on reforms to the CM in October 2015 and the conclusions and decisions of UK Government have been published. The three more important aspects that the consultation covers are (DECC, 2016):

- Buying more capacity in the next auctions, and buying it earlier.
- Tightening delivery incentives and penalties
- To introduce a supplementary one year-ahead capacity auction in 2016 for the delivery year 2017/2018 for tackling how wholesale prices impact in the short term on energy security.

[31] The System Operator publishes technology specific de-rating factors in advance of the pre-qualification process, which apply to all plants of a specific technology, irrespective of their age or status. These factors are based on class type historic performance over the previous seven years and represent the average expected contribution of plants at times of system stress on a technology specific basis (European Commission, 2014b).

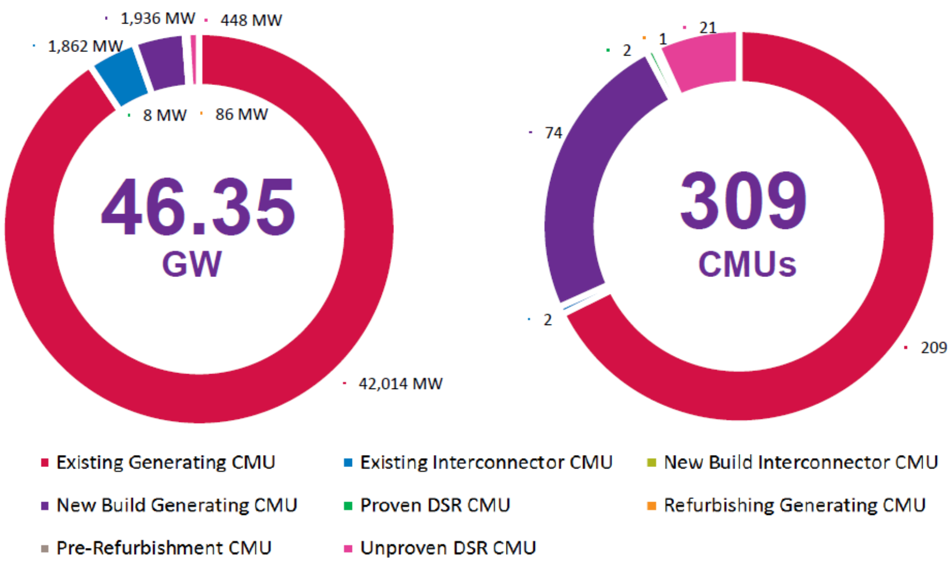

Figure 81. Awarded capacity by Capacity Market Unit (CMU) type in the second T-4 capacity auction. Source: (National Grid, 2015a)

C.2. De-central obligations – France

Concerns about the functioning of electricity markets have a special resonance in France due to the specific characteristics of its power sector and notably the peak demand phenomenon observed. The peak demand phenomenon refers to the fact that peak demand is growing faster than demand in general terms. The adequacy studies conducted by the French SO, *Réseau de Transport d'Electricité* (RTE), show that temperatures are the dominant variable for the French power system. As a result, the risk of shortfalls are mainly observed in winter during cold spells.

The CRM was designed to address this issue by modifying consumption behaviour during peak periods (demand-based approach) while encouraging adequate investment in generation and demand response capacities (supply-based approach).

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C.2.1. Design characteristics

Eligibility

All potential capacity providers including demand response and storage and both new and existing projects can be granted capacity certificates in the French scheme, the certification is requested by the capacity provider and determined by RTE.

Even if the mechanism is not currently open to interconnectors or foreign capacity participation, a public consultation has been launched in order to assess the potential for direct interconnector or foreign participation in future.

Moreover, the mechanisms allow RES producers to participate and are awarded certificates. In order to avoid double payment, the producers receive the higher of the income from the certificates or the "normal" RES subsidies).

Allocation process

In the de-central obligation model there is no central buyer but capacity certificates are tradable, so once suppliers have an obligation to hold capacity certificates a market is created. The certificates can be bilaterally traded, or potentially traded on exchanges. The bilateral trade is based in a mutual agreement of the object and price of the trade and then, the agreement should be notified to RTE.

The central authority establishes only the coverage rate of expected demand that market participants need to attain. The amount of capacity needed to ensure SoS is not determined ex ante but is estimated by individual suppliers, which have the obligation to procure enough capacity to cover the need for their customers from capacity providers. Then, this means that they have to forecast the demand. Nevertheless, after the estimation of the amount of capacity to be procured by suppliers, the TSO determines ex-post the correction factor to be applied to the total demand to simulate severe winter conditions.

A capacity guarantee is only valid for one year of delivery: if it is issued for a specified year of delivery, it cannot be transferred to a different year of delivery.

Capacity product

Under this scheme, capacity providers are only obliged to make their capacity available in specific hours where demand is highest. These hours can take place in a maximum of 25 days a year, and are announced day ahead by RTE. For each peak day, the time slots considered are from 7am to 3pm and from 6pm to 8pm, or ten hours per day. Peak days will fall within January-March and November-December periods.

In these hours, to cover the consumption of their consumers in a cold winter, suppliers must either own production plants or energy curtailment system, or purchase capacity guarantees from other energy suppliers in the form of certificates. A taxonomy of this mechanism is shown in Figure 82.

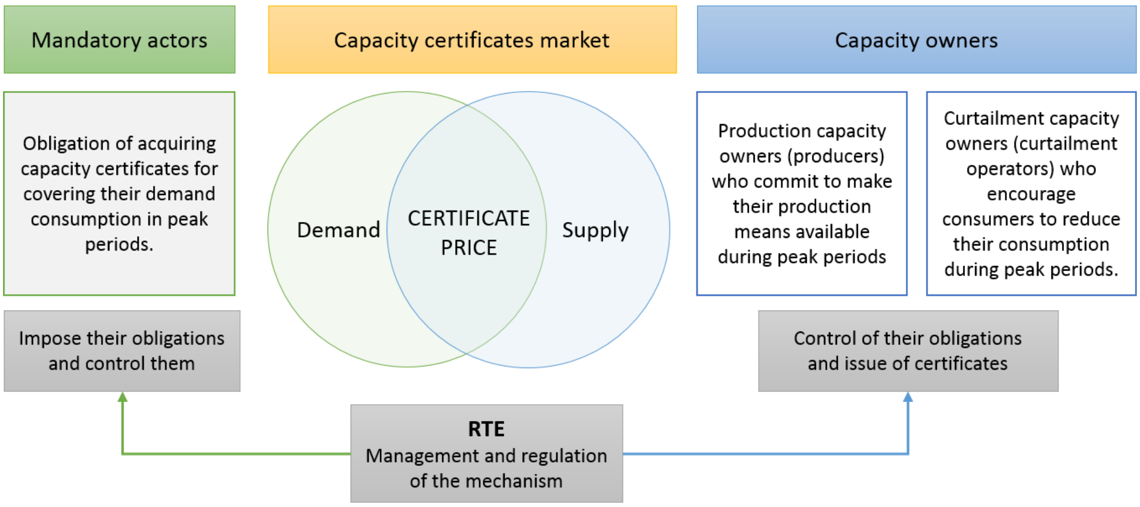

Figure 82. Taxonomy of the de-central obligation model in France. Source: Own elaboration from (Norton Rose Fulbright, 2015).

Suppliers' obligations are calculated based on the type of consumers they supply, this is, it will depend on their consumers who consume in peak periods. If suppliers hold insufficient certificates, or capacity providers make insufficient capacity available, capacity imbalance penalties will apply. Capacity obligations are calculated as follows:

$$Obligation_{Sup} = SF \cdot \left[Consump_{Sup} + P_{DR} + Gradient_{Sup} \cdot (T_{ext} - T_a)\right]$$

Where SF is the security factor that is calculated for each delivery by RTE, it takes into account possible contributions of interconnectors during peak periods. It also sets the extreme temperature of reference (T_{ext}). $Consump_{Sup}$ is the reference power by type of consumer and P_{DR} is the load reduction for certified demand response capacity activated. $Gradient_{Sup}$ is applied in order to represent the different contributions of consumers to the shortfall risk. The actual temperature (T_a) is measure (RTE, 2014).

The time gap between the allocation and the delivery obligation varies from 2 month to 4 years for demand response and new generation plants and form 3 to 4 years in case of existing generation capacity. The contract duration is 1 year for all types of capacity providers given that every year the energy suppliers are assigned a new capacity obligation.

C.2.2. Design issues

A de-central obligation mechanism may not be appropriate if there is a perceived risk that an incumbent with some degree of market power may abuse its position in the trade of the obligations. The dependence on bilateral trading model without mandatory exchange trading risks gives competitive advantage to vertically integrated companies that trade certificates internally between their generation and retail businesses. This is likely to increase incentives for vertical integration and reduce those for new independent entries.

Other issue that might arise is the risk of over or under-procurement. For instance, if the design of penalties that apply for insufficient procurement allow suppliers to strategically underestimate their expected demand to reduce procurement costs, or are so high that suppliers hedge the risk by purchasing extra capacity.

In regard to contract duration, long term signals are needed so as to foster new investments, for example by trading long-term contracts with suppliers. If this contract do not emerge from the market, sufficient investments might not occur (EURELECTRIC, 2015b).

C.3. Reliability options – Italy

Italy is planning to replace its existing targeted capacity mechanism with a central buyer mechanism based on reliability options contracts traded in auctions where the counter party will be the Italian TSO, Terna.

C.3.1. Necessity

In Italy, like in most other EU Member States, the impact of the economic crisis and the resulting reduction of demand for electricity, combined with the growth of both conventional and renewable capacities, have led to the current situation of overcapacity and low wholesale market prices. However, given the intermittent and uncertain volume of energy production from renewable source, the concern about the ability to produce sufficient capacity to meet electricity demand indeed materialized in 2003, when a full blackout occurred (except in Sardinia and Elba). After that, a provisional system was put in place before a definitive implementation of the capacity market mechanism base on reliability options contracts here introduced. According to the results of sector inquiry on capacity mechanism (European Commission, 2016b), the large majority of Italian market participants states that the current capacity payment mechanism is too low to cover their costs of availability, and as a consequence, concerns on peak demand coverage are expected in the future.

C.3.2. Design variables

<u>Eligibility</u>

Both new (planned or under construction) and existing resources are admitted (AEEG, 2011). However, they should comply with the following requirements:

- Non-intermittent or programmable (for instance: thermal, pumping storage, conventional hydro, etc.)
- Not be receiving any other type of investment incentive scheme;
- Not subject to dismantling measures approved by the competent authorities.

Although still in development, it intends to be open to all potential capacity providers including also DSR and foreign capacity as of 2017 auction. However, currently there is in place an interruptibility scheme targeted to demand response.

In terms of geographic scope, considering the significant transmission constraints within Italy, the mechanism is being designed as a zonal system which will establish different prices for capacity per zone. For this reason Terna carries out adequacy assessments for the whole of Italy and for each zone and, therefore, zonal capacity auctions will be held. Terna will have to assure that assets in one zone contribute to SoS in another zone as much as possible (EURELECTRIC, 2015b).

<u>Allocation process</u>

The central buyer mechanisms involve a central process in which all capacity providers offer their capacity where Terna is the central counterparty, that is to say, it buys the capacity on behalf of electricity suppliers/consumers. The system will include three different types of auctions and a secondary market which are introduced in Table 27.

Table 27. Market structure of the Italian capacity market Source: Own compilation (from Terna and AEEGSI).

Main Auction	Procurement of capacity. Terna signs contracts with power producers for long term supply.	• Lead time: 4 years • Delivery period: 3 year
Complementary auction	Provision of additional capacity on the basis of the main auction's mechanism, negotiating shorter delivery periods with proportional reduction of premium	• Lead time: 4 years • Delivery period: 1-2 year
Adjustment auction	Capacity providers re-negotiate the products acquired in the main auction. Terna adjusts the adequacy target if required.	• Lead time: 3 to 1 years • Delivery period: 1 year
Secondary market	Power producer trade their contract to adjust their positions. Re-negotiation of the products acquired in the previous auctions (sellers)	• Lead time : less than 1 year • Delivery period: 1 month

The main and the complementary supply auctions are held in a yearly basis, where power producers can sell a reliability option contracts to Terna, covering the amount of back-up capacity needed for that year according to Terna estimations. In the adjustment auction capacity providers can renegotiate their contracts to adapt to possible variations of adequacy targets communicate by the TSO. The three actions are held yearly and take the form of a descending clock auction, whereas the secondary market negotiations will take place on a continuous basis, with weekly sessions, with a lead time shorter than one year and 1 month delivery period (AEEG, 2011).

The target capacity to be made available will be determined by Terna on the basis of the expected consumption and reserve requirements, taking into account the effects of energy efficiency measures and renewable energy production. It will be a function of VoLL, LOLP and Variable Cost of the marginal technology and an elastic yearly demand curve will be set for any relevant area (Valeria Termini, 2014). The following Figure 83 represents the demand curve as well as agents' offers. P* is the premium get by all agents awarded with a contract for the clearing quantity procured Q*. Ineligible providers, whose bid is considered to be 0 €/MW do not receive the premium.

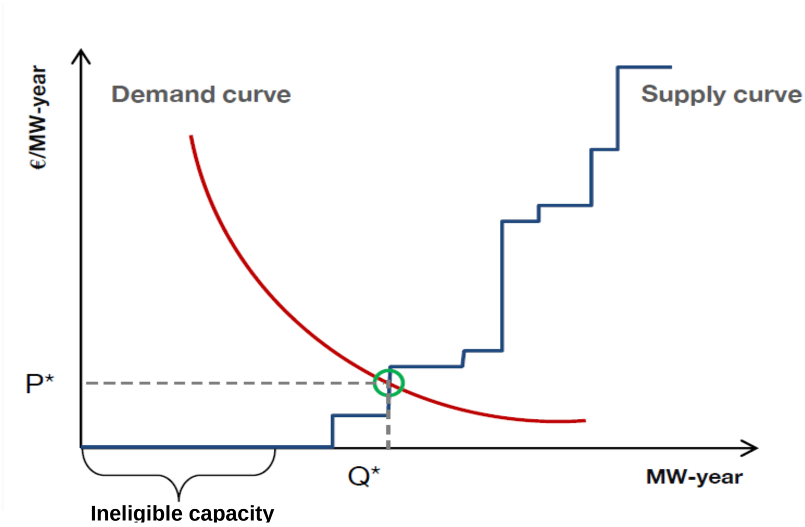

Figure 83. Adequacy target in the form of an elastic yearly demand curve and supply curve intersecting in the auction clearing price. Source: (Terna, 2015).

Participation in the mechanism is voluntary, but subject to the presentation of the required guarantees to Terna. The amount of capacity submitted by each participant cannot be greater than its expected available capacity, which is also defined by Terna individually for each power plant.

<u>Capacity product</u>

In Italian mechanism, the capacity product is a reliability option. When a scarcity situation arises, capacity providers with a certain capacity contracted are obliged to pay to Terna any positive difference between the spot price and the strike price for the capacity contracted and during the contract duration. These so called 'critical days' are defined in advance of each delivery year by Terna.

In order to maintain liquidity and have good price signal of scarcity, the second obligation of participants is to submit offers in the day-ahead market for all their contracted capacity. Any remaining capacity must then be bid into the ancillary services market and balancing markets (AEEG, 2011).

Strike price is the standard hourly variable cost of the marginal technology which is the technology with the lowest annual fixed costs or, according to (Valeria Termini, 2014), an 'efficient' peak plant. The penalties applied will be linked to a VoLL of 3,000 €/MWh (as far as the price cap is eliminated) and to the reference price (European Commission, 2016b).

The availability obligation is given in return of a premium (€/MW/year) set by the auction clearing price, for their capacity obligation (MW/year) which is the clearing quantity committed.

C.3.3. Issues

The three year delivery period intends to reduce the risk for the participants in the capacity mechanism and therefore it can also increase participation, particularly by demand response providers which may struggle to ensure capacity over longer durations. However, this decision should take into account that if it results to be limited, also more limited capacity will be brought into the system. In this vein, it has to be taken into account that the mechanism has the risk of not bringing new capacity into the system. However, it seems not to be a problem considering that the underlying aim of the mechanism would have been avoiding existing plants to abandon the system. (European Commission, 2016b).

Regarding the lead time, it intends to promote competition between existing and new capacity (Valeria Termini, 2014).On the other hand, four-year might be too long for demand response providers so as to commit. Nevertheless, the existence of several auctions to re-negotiate positions, including the shortening of the contract duration, should alleviate this problem.

As it has been previously mention, the obligation of participating in the day-ahead, ancillary service markets and balancing markets intends to release a reference spot price which will provide to the holders of the reliability option contract a proper scarcity price signal. Thus, an incentive to be available in case of a scarcity actually materialized while ensuring the day-ahead market remains liquid. Without the obligation to bid day ahead, participants might withhold their capacity until closer to real time in order to increase prices and ensure enough incomes to payback Terna the difference between the spot and strike prices.

C.4. Capacity payments – Portugal

Portugal operates two targeted capacity payments schemes since 2010: one designed for remunerating thermal plants for being available (the 'availability incentive') and the other aimed at fostering investments in hydro power plants and pumping storage units (the 'investment incentive'). In 2012, Portugal approved a normative (*Portaria nº251/2012*) about the capacity payments in line with the MIBEL proposal.

C.4.1. Necessity

As in many European countries, Portugal has experienced a notable rate of RES penetration and is expected to further increase so as to reach their 2020 targets. Therefore, the need of flexible backup generation able to alleviate the risk that the intermittency and uncertainty of these sources may provoke in the SoS should be faced.

On the other hand, after the start of the economic crisis, the Portuguese production and demand started to decrease, leading to a significant overcapacity and to a missing money problem for some thermal power plants. The relatively low price cap characteristic of the Portuguese electricity market (180 €/MWh) is far from letting the market price to rise enough so as to represent a good economic signal for participants.

C.4.2. Design variables

<u>Eligibility</u>

The investment incentive is a targeted capacity payment aimed only at hydro power plants (new plants and repowering of existing plants). Whereas the technologies eligible to participate in the availability incentive scheme are thermal generation capacity. Both mechanism contemplate a size requirement of minimum of 30 MW in order to be eligible (Ministério da Economia e do Emprego, 2012).

<u>Allocation process</u>

Those agents interested in participating in one of the mechanisms have to request their admission to the allocation process for both capacity payments follows and administrative procedure, where the TSO selects the plants that can participate and, together with the Government, estimates the reserve margin that will determine eventually the payments[32].

Capacity product

The contract length is 10 years in the case of the investment incentives beneficiaries. On the other hand, the availability incentive contract period is the entire operational lifetime for new plants and the remaining lifetime in case of existing plants.

The level of remuneration of the investment incentive is explicitly and automatically tied to the reliability standard through the so called 'Reference Investment', which is calculated taken into account the Coverage Index (CI). It results inversely proportional to the Portuguese CI so it varies along with the variations of the SoS needs in its calculation every year. If there is overcapacity the remuneration should tend to zero in order not to attract new investments. The level of remuneration is also linked to the installed capacity, to the fulfilment of the time terms of the commissioning of the plants (penalizing delays and awarding the prompt fulfilment) and to an index dependent on a coefficient of availability ('cdf') characteristic of each generating group, which is calculated taken into account the historical values of the available active power of the two previous year to the incentive payment (Ministério da Economia e do Emprego, 2012).

In the case of the availability incentive, the level of remuneration is proportional to a reference availability incentive (6,000 €/MWh in 2012), to the installed capacity of the plant and to a coefficient dependent on the 'cdf'.

There is no limitation of use on the availability incentive capacity providers, meaning that all remunerated capacity providers are obliged to provide energy whenever the TSO considers they are needed through the whole operating lifetime of the plant. Moreover, the truly availability of the plants is frequently tested. On the other hand, both availability and investment incentives, plants can loss the whole capacity payment if they are available less than 70% of the time. Even more, if repetitive unfulfilments are observed, they could eventually be excluded from the mechanism.

C.4.3. Design issues

Portugal (together with Spain) have the lowest capacity payments in Europe despite high penetration of renewables. In fact, the payments to CCGT power plants lost the incentives in 2012 and 2013, and from 2014 they were reduced till be set around 6,000 €/MW/year (EDP, 2012). The level of remuneration for incentivizing investments has changed significantly over time leading to a regulatory uncertainty that has undermined the economic signals for attracting new investments and only prevention of plants from exiting the system seems to be achieved.

Moreover, the Portuguese respondents of the sector inquiry affirms that the current investment incentive is not enough for hydro plants to recover their investment or repowering costs (European Commission, 2016b). This reveals that even if the level of remuneration is somewhat linked to the CI and could therefore potentially send the right economic signal at all times, the fact that a non-competitive allocation process is in place, leads to flawed incentives.

[32] An adequacy assessment is carried out and the so called Coverage Index is calculated following the methodology approved by the General Directorate of energy and Geology (DGEG) (Ministério da Economia e do Emprego, 2012).

C.5. Strategic reserves – Germany

C.5.1. Necessity

The German strategic reserves mechanism, called 'network reserve', is aimed at preventing the closure of power plants located in southern region of the country. The high rate of RES penetration as a result of the feed-in tariffs along with the phasing out of nuclear power plants taking place in the country, have led to local SoS concerns. Moreover, some power producers (mainly CCGT) declared its intention to close from 2016 on, because they could no longer supply power to the market at profitable terms.

In the long term, these could be alleviated by investing in transmission lines for crossing the country in order to distribute the relevant amount of energy produced by the numerous off-shore wind farms located in the North, and meet the higher level of demand characteristic of the South. For this reasons, the network reserves mechanism seems to be a proper election for a temporary measure.

C.5.2. Design variables

<u>Eligibility</u>

The reserve providers are mainly power plants that are willing to close but, owing to be considered essential for the system SoS, are forbidden to do so. By its definition, the mechanism is open to all types of plants and storage providers that have declared their intention to close or mothball and are considered 'system relevant'.

In case that the network reserve results insufficient, a tender for additional capacity is contemplated and will permit the participation of foreign capacity and storage provided that can contribute to alleviating the shortage problem through re-dispatching abroad.

Even if nowadays the mechanism is targeted at existing capacity providers, Germany is planning to include new generation capacity in a revision of the mechanism (European Commission, 2016b).

<u>Allocation procedure</u>

The allocation procedure depends on the type of reserve defined in the mechanism, i.e. the mandatory part and the voluntary part.

For the first one, an administrative procedure is in practice. The remuneration is bilaterally negotiated between the TSO and the eligible capacity providers by following a methodology defined by the regulator.

The voluntary part of the network reserve is allocated through a competitive procedure instead. It consists in a tender procedure where the successful participants are paid following a pay-as-bid rule.

<u>Capacity product</u>

The lead time also varies with the type of reserve. In the case of the mandatory network reserve, the time between the award of the contract and the beginning of the delivery period is at least one year, that is to say, the intended closure must be notified 12 months ahead. Whereas the voluntary party lead time is 4.5 months, time lapse between the celebration of the tender and the beginning of the delivery obligation. The contract length will vary from 2 year to up to 5, depending on whether the closure of the unit is definitive or preliminary (European Commission, 2016b). However, plants providers of network reserves can be forced to stay in the system beyond the established contract duration as far as the TSO decides they are still 'system relevant'.

The main obligation of these reserves is to not participate is the market once the contract has started. They have to be available to be dispatch by the TSO, whenever after the day-ahead market or the intraday market having taken place, the resulting dispatch reveals congestions from north to south.

C.5.3. Design issues

One concern of the German network reserve is the fact that there are less offers than demand of load. This means that, even if the allocation procedures was intended to be volume-based, it has ended up in a negotiation of the contract between the TSO and the providers under a methodology stated by the regulator.

Regarding eligibility, this mechanism is a perfect example of design for addressing locational SoS problems. Specifically it is addressed at solving a congestion problem between North and South aggravated by high South demand and high North generation. This fact means that the market is failing at sending the proper investment signal for solving the lack of generation capacity or the lack of interconnection. In this case, there is a plan of increasing the interconnection capacity from North to South, however this project takes time. Therefore, as far as this mechanism is just implement as a temporary mechanism it look like a proper measure.

C.6. Tenders for new capacity – Ireland

C.6.1. Necessity

The purpose of the implementation of this scheme in 2003 was to bring new capacity into the system in order to hedge the continuous demand growth expected. The 2003-2009 adequacy report released by the TSO revealed that shortage of capacity was expected for 2005 onwards. Specifically, 300 MW of additional capacity installed was required by 2005, 250 MW in 2007 and 150 MW in 2009. For this reason, a process to get into the system 531 MW as soon as possible was required (EC, 2003).

C.6.2. Design variables

<u>Eligibility</u>

In the mechanism, contracts were offered to new generation capacity only. Specifically, it was opened to any new centrally dispatchable thermal plant, with a planned capacity greater than 50 MW (EC, 2016b). Plants based outside Ireland were allowed to participate, to the extent that they could prove that they are or will be able to provide electricity via interconnectors (EC, 2003).

<u>Allocation procedure</u>

The allocation process was a competitive bidding process where the cheapest offers were granted with an agreement. The details defining all indispensable parameters for the process were established ex-ante in the tender documents, which were provided to potential bidders. (EC, 2003).

<u>Capacity product</u>

The contract agreement is called Capacity and Differences Agreements (CADA), which was granted to generators for at most 10 years (they can exit the contract when they wish) (EC, 2003) and with a led time of 3 years (it was not set ex ante but agreed by tenderers) (EC, 2016b). They have the right to receive a capacity payment in base of their availability and are free to run in the market and earn separated electricity revenues. This commitment represents just a financial instrument (one way call option) since generators are not obliged to physically deliver energy but to return any positive difference between the reference market price and the strike price. This last corresponds to the short run marginal cost of the most efficient new CCGT (EC, 2003).

C.6.3. Design issues

Any design issue seemed to arise with this mechanisms. The target capacity of 531 MW was met by only two plants: one CHP and one CCGT (EC, 2016b).

C.7. Issues encountered in other international experiences

C.7.1. Latin American mechanisms

Argentina

In the capacity payment defined in Argentina in 1995, the remuneration was linked to the actual production of the units, consequently, generators bids included the internalization of the payment leading to infra-marginal cost bids so as to receive the capacity payment and therefore affecting the efficiency of the final dispatch.

Guatemala

One problem in Guatemala's capacity market was the definition of the reliability product: the payment was linked to the availability in the dry season and the firm supply was based on the variable costs (the smaller the variable costs the bigger the firm capacity acknowledged).

Specifically, the payment to hydro units was linked to the historical production of the units that can be assured in 95% of the cases in the four peak hour of the working days of the dry season and for thermal units, it depended on the historical average failure rate (Carlos Batlle, 2010). Firstly, this led to hydro unit keeping more resources for the dry periods shifting them from the wet periods and causing possible spillages if an unexpected inflow occurs when the reservoir was near to its full capacity (Pérez-Arriaga, 2013). Secondly, thermal inefficient plants with low investment cost and high variable cost took advantage of this unflawed definition of the product: they offered their capacity at low prices, so only they entered the system while new efficient entrants were prevented (Carlos Batlle, 2010).

Brazil

In 2001 and 2002 rationing periods took place in Brazil during a draught (see Figure 84). After a thorough analysis of the mechanism in place (obligation on regulated retailer to contract in the long term 85% of their expected demand and a floor price to overcome the common zero prices) some imperfections regarding expansion and contracting where detected. Firstly, the spot market price did not represent a proper economic signal for fostering new investments. Secondly, the combination of a strong demand growth with a large volatility in the growth rates (L.Barroso, 2007). Then, a new mechanism was proposed: a scheme base on reliability option.

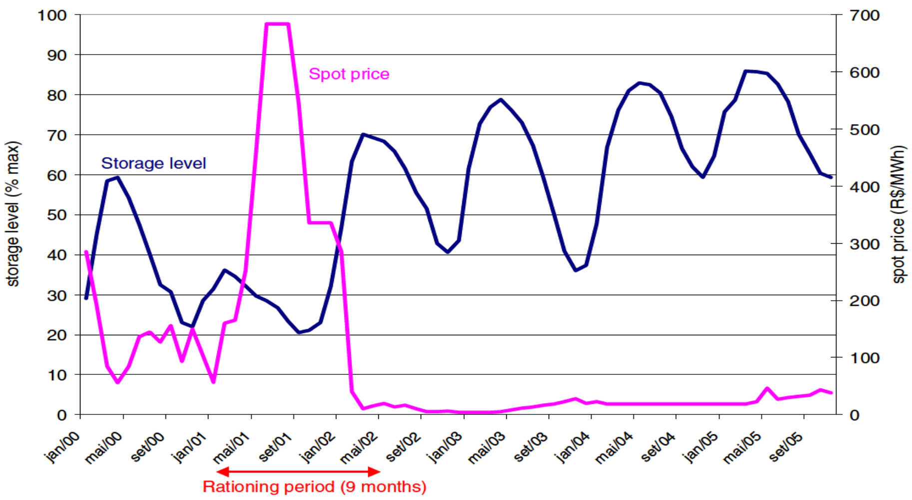

Figure 84. Short-run marginal costs (R$/MWh) and storage levels. Source: (L.Barroso, 2007).

Chile

The Chilean electricity power system had very similar concerns as the previously mention Brazilian system: uncertainty and volatility of hydrology and demand growth. According to the previous regulatory model (before the implementation of reliability options mechanism in 2006), the '*energy consumer price was calculated by the government every six months as a unique value which represented the expected marginal cost of generation and losses in transmission system*' (L.Barroso, 2007). Given that the 22% of the supply came from natural gas plants, when restrictions of natural gas imported from Argentina arose, the price did not reflect the increment in generation costs and therefore the investments in new generation dropped abruptly.

C.7.2. North America mechanism

Eastern USA (PJM, NYISO and ISO-NE)

The ICAP capacity market (a de-centralized obligation onto LSE with capacity credits) has been modified along the years in an attempt to solve the several problems related to the definition of the remuneration level and the reliability product. Initially, it was linked to the actual Installed Capacity (ICAP), but not all the capacity were always and equally available. Then, it was introduced a de-rating to the Installed capacity based on the average historical availability, i.e. the term Unforced Capacity (UCAP) was introduced. However, it was calculated as an average of the availabilities during a long period without taken into account the availability in scarce situations which did not incentivize the actual production in shortage periods. Finally, the obligation of offering capacity in the DAM market (must-offer) together with a penalty for unavailabilities were introduced. Nevertheless, as it has been said in subsection x, it has to be considered that the must-offer may lead to generators bidding high enough for not being dispatched and not being penalized.

In PJM market, three problems were detected: no recovery of the investments costs, high capacity price volatility (long periods of zero price followed by high spikes periods as figure x shows) and lack of locational signals. In order to alleviate these problems, the demand of capacity was change from a quantity curve to a price-quantity curve. Moreover, it was proposed the increment of the lag period and the contract duration in order to foster new entrants and overcome the lack of installed capacity as a result of long zero prices periods (Carlos Batlle, 2010).

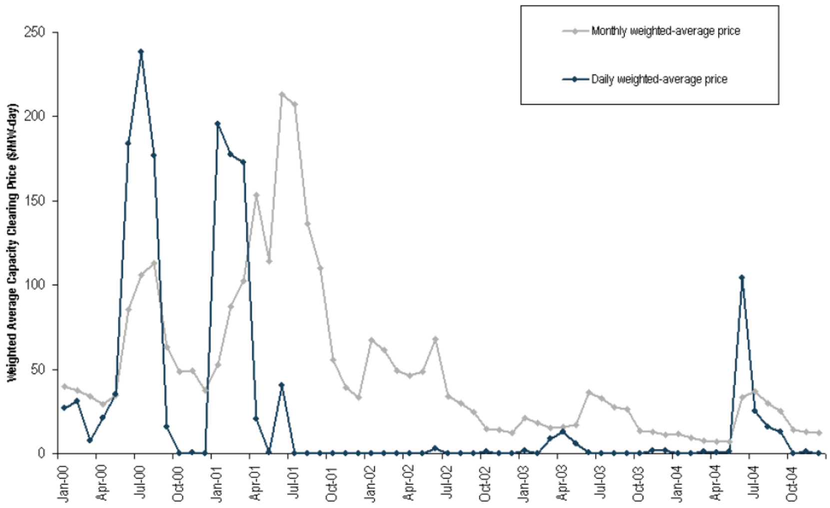

Figure 85. Average capacity prices. Source: (Carlos Batlle, 2010).

Also the congestions should be considered in these markets, in order to reveal locational SoS issues. The more recent central buyer model implemented in ISO New England and PJM actions take into account zonal capacity prices (European Commission, 2016b).

C.7.3. Other European experiences

UK

The capacity payment in place in UK during the period 1990-2001 was criticized because of an unflawed definition of the methodology used to calculate the availability factor of the units. The capacity payment level was equal to the LOLP times the VoLL, so some plants tended to declare themselves as unavailable in order to increase the LOLP and therefore the payment (Carlos Batlle, 2010).

Ireland

The capacity payment in place in Ireland under the Single Electricity Market (SEM) was updated yearly. For this reason, capacity providers had no certainty of incomes and therefore not enough incentive to invest in new capacity.

Annex D. **Description of the Iberian wholesale electricity market model**

The **E**lectricity **P**rice **Si**mulator for **Lon**g-term analysis (**EPSILON**) is a wholesale electricity market model designed and implemented by the Economics & Regulation Practice of KPMG Spain.

EPSILON has been used in many consultancy projects requiring long-term estimates of scenarios of electricity prices and generation mixes in the Iberian market, including due diligences, arbitration procedures or impact assessments of energy policies and regulatory decisions.

EPSILON is implemented in Visual Basic for Applications (VBA) and can run simulations of up to a decade in a few minutes.

The inputs used by EPSILON to carry out simulations of the wholesale market include the projections of annual levels of demand, prices of commodities, generation mix structure, technical features of the generation fleet, available water resources as well as historical data of hourly profiles for RES technologies and demand.

On this basis, EPSILON will provide a forecast of hourly electricity prices, production per technology, capacity margins, full-load equivalent hours, levels of RES curtailment and energy non-served, etc.

In the next paragraphs, a detailed description of the input data used to define the generation fleet and the demand are described, as well as the algorithm used by EPSILON to clear the market.

D.1. Modelling of variables in EPSILON

D.1.1. Demand

Demand is projected using two sources of data. Firstly, a real historical profile of hourly demand in the Iberian system. This profile is used to define the shape of the hourly demand that needs to be met by the generation fleet.

Secondly, this profile is transformed into a vector of hourly demand by adapting it to the specified annual demand.

D.1.2. Interconnector flow

The projection of the flows in the interconnector in each hour are made in an equivalent way to the approach used for demand. This projection is made in a separate way for import and export flows. Attention is paid to the use of interconnector and demand reference profiles of the same year, in order to implicitly incorporate coherence to the final hourly demand that includes interconnector flows.

D.1.3. Generation

D.1.3.1. RES

Different RES technologies can be modelled in EPSILON: wind power, solar PV, solar thermal, small-hydro, renewable and no-renewable waste and CHP. The approach used to model the hourly production is the same explained for the cases of the demand and the interconnector flow.

The annual production of each RES technology is defined by the installed capacity and an annual production expressed by the load factor. This formulation allows to take into account the fact that different levels of RES penetration achieve different levels of annual equivalent full-load hours.

D.1.3.2. Thermal fleet

The definition of the thermal fleet is based on the concept of *technologies.* Each technology comprises a set (i.e. from one to several) of identical generation units in terms of type of fuel, variable cost, heat rate, variable costs, unitary capacity, investment cost, etc.

The number of technologies that can be defined is flexible, and it depends on the needs to focus on detailed features of specific units. For instance, a full definition of the generation fleet can be made if each technology is defined as a single generation unit.

Typically, thermal technologies are split into nuclear, domestic and imported coal, and CCGT.

Thermal generation costs are modelled as:

- Fixed operation cost: It is a value expressed in €/MW/year that stands for the costs that a generating unit would incur irrespective of its participation in the market.
- Variable operation cost: It is a value expressed in €/MWh that stands for the marginal cost that a generation unit would incur when it is dispatched in the market. It is computed using commodities (i.e. fuel and carbon) price, fuel transport cost, the heat rate, the emission factor, O&M variable costs, environmental taxes, access tariffs for natural gas and electricity grids, and the 7% TVPEE of Act 15/2012.

Thermal units are assumed by default to bid their variable cost in the market i.e. perfect competition is assumed.

Must-run features can be defined for technologies, entailed that they are dispatched at their full available capacity in each hour. This is commonly the approach used to model nuclear power plants production profile.

However, EPSILON allows defining certain variable offer cost slopes so as to allow that units of the same category offer with certain differences so as to better capture an implicit merit order within very similar generation units.

Additionally, it allows configuring a certain factor that models the uplift that generation units are incentivized to offer in the market if imperfect competition is considered. This strategic bidding parameter is defined as a function of the reliability index of the system and it can be used to describe the existence of scarcity prices.

D.1.3.3. Hydroelectric power

The parameters of hydropower describe the large hydro fleet of the Iberian system, including the generation capacity of the mixed-pumping portfolio.

The production of the hydro fleet is defined on the basis of five inputs:

- The installed capacity of large hydro.
- The annual production of this technology.

- The monthly allocation of production, in relative terms, of the total annual production.
- The minimum hourly production of this technology on a monthly basis, that can be defined as the run-of-the-river component of the large hydro production.
- The maximum hourly production of this technology on a monthly basis.

The monthly share of production, the maximum and the minimum production (in relative terms with regard to the installed capacity) have been derived from historical data consistent with the annual levels of the annual production used in the simulations.

D.1.3.4. Pumping

Pumping is modelled on the basis of five inputs:

- The performance of the transformation of energy from pumping to generation. A performance of 70% has been used.
- The installed capacity of pure and mixed pumping.
- The annual production of this technology.
- The maximum hourly production of this technology

D.2. Market clearing algorithm

EPSILON follows a series of subsequent stages in order to clear the market and produce the outputs of the simulation, as explained next:

D.2.1. Determination of the net demand

The first operation carried out by EPSILON is the separation of the chronological hourly profiles (RES and demand) into as many subperiods with homogeneous variables exist. This typically entails the creation of 12 different subperiods corresponding to the different months in which hydropower and pumping features are different.

Focusing on a one-month length series of chronological demand values, the first operation is to subtract on an hourly basis: (i) the thermal must-run production, (ii) the interconnector flow, (iii) the RES production and (iv) the run-of-the-river component of the large hydro in order to build the so-called net demand.

In the event that this operation leads to negative values of the net demand, it usually entails that RES curtailment episodes arise. This information is stored as it will be considered in the module devoted to the pumping optimization.

D.2.2. *Building the set of monotone net demand curves*

Once the net set of net demand curves are built (one per month), they are transformed into the monotone-ordered curves.

D.2.3. Hydro dispatch

The hydro dispatch is performed according to the peak-shaving algorithm, and carried out separately for each of the subperiods in which the available hydro resource as well as the achievable maximum power are different.

This algorithm tries to produce as much as possible with water resources in the hours in which the net demand is higher, entailing that high-price thermal units would otherwise be called to produce. The maximum hourly production is however limited by the maximum instantaneous power that can be achieved. Similarly, the monthly maximum energy production entails a constraint.

Once the monotone net demand curve has been subject to the hydro dispatch, it is sent to the thermal dispatch module.

D.2.4. Thermal dispatch module

The thermal dispatch module is used to decide the dispatch of the thermal units which are not working under a must-run approach (i.e. coal and CCGT).

For each hour, the remaining demand (net demand after the hydro dispatch) which is assumed to bid as inelastic demand, is cleared against a merit-order curve of generation offers.

This entails that thermal technologies will be committed in each hour starting from the cheaper one until its capacity is exhausted and following the second least costly unit, etc. until the demand is met

When the aggregate of available capacity cannot meet the demand level, energy non-served arises and the cap price of the MIBEL is set in that hour.

Otherwise, the marginal price will be that of the offer of the last technology that has been committed.

This procedure is followed on an hourly basis throughout the whole scope of the simulation.

D.2.5. Outputs

The outputs of EPSILON are very flexible and can be adapted to the specific needs of the analysis that is being carried out.

Typically, EPSILON will provide with a detailed analysis of the hourly production per technology, hourly prices, levels of curtailment and energy non-served, annual emissions, dispatch cost, pumping production, etc.

Figure 86 shows an example of a dispatch and the hourly prices obtained in a simulation with EPSILON.

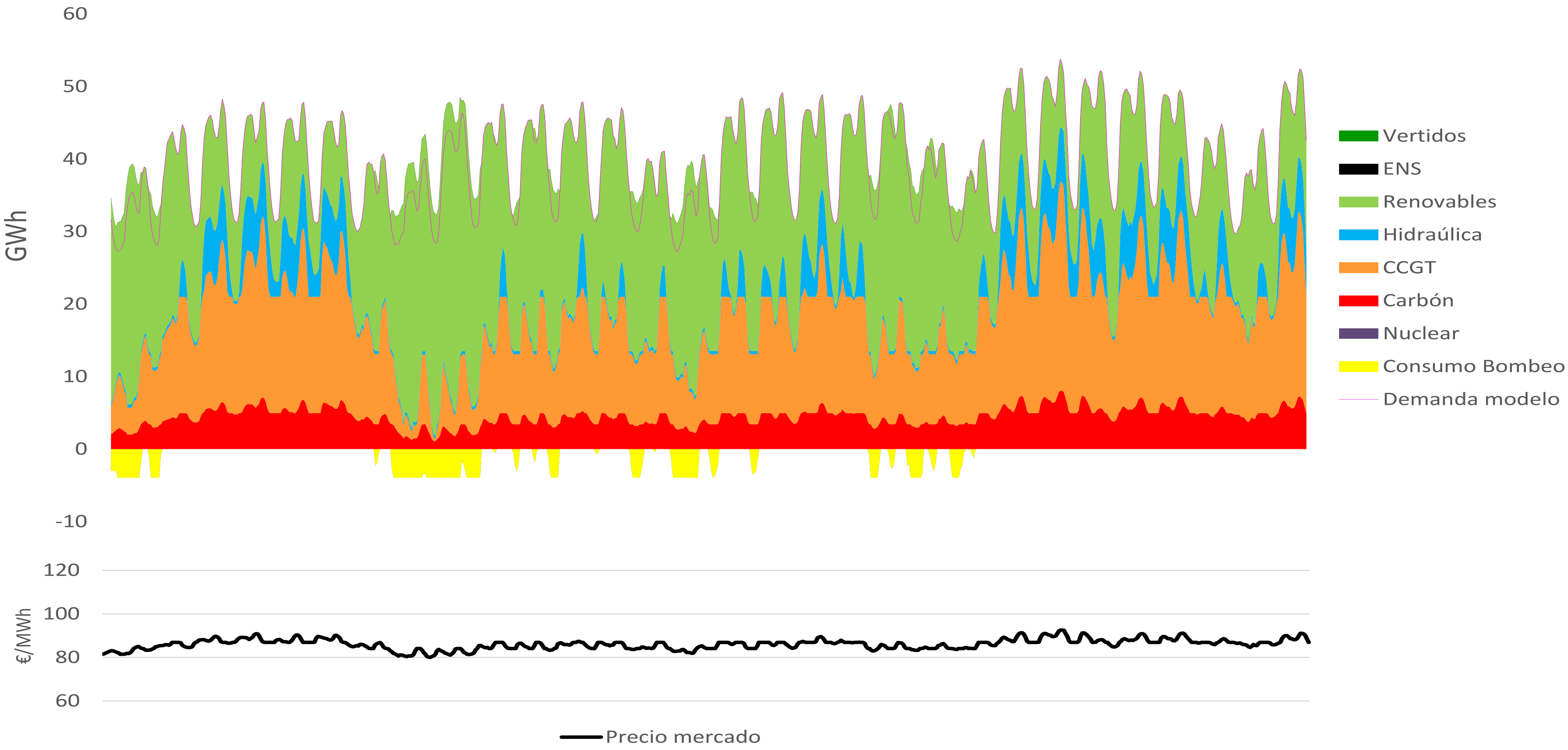

Figure 86. Monthly dispacht of the KPMG Iberian Electricity Market Model.