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Enhancing power supply adequacy in Spain: migrating from capacity payments to reliability options*

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Abstract There has been total unanimity about the vital importance of reliability of supply since the beginning of the electricity sector deregulation process. This paper describes the procedure proposed by the "White paper for the reform of the regulatory scheme of the power generation in Spain" (Pérez-Arriaga 2005) to improve upon the current scheme to guarantee a reasonable reserve margin, the capacity payment mechanism. This alternative design introduces improvements aimed at guaranteeing at least a minimum capacity reserve margin, as well as at providing a strong incentive for generating units to be available when needed, namely, in situations when supply is likely to be insufficient to meet the total demand.

1   INTRODUCTION

Designing a stable regulatory framework, so that electricity can be delivered efficiently and reliably now and in the long term, happens to be a major concern of regulation policies in electricity markets. Since the choice of a regulatory framework that is open to

competition whenever possible is an accepted principle, the key issue now is how to introduce any necessary adjustments in the initial designs of the markets that have been implemented already, so that the identified shortcomings are eliminated and any necessary regulatory measures to be introduced interfere as least as possible with the functioning of the market, while ensuring the long-term sustainability of the model. There is total unanimity about the relevance of reliability of electricity supply, and experience shows that extended or systematic interruptions can lead to political or market model crisis (for instance, California and Ontario chose to modify drastically their market models after an episode of extended rationing).

The National Electric Reliability Council in the U.S.A. defines reliability as 'the degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired'. Therefore, the ultimate measure of the reliability of the generation activity is the level of quality of supply provided to the load by generation at the wholesale level. Although the quality of supply only materializes in real time, its provision encompasses a number of deregulated activities that have to be performed in different time ranges, from several years to seconds, such as investment in new facilities, scheduled plant maintenance, fuel acquisition and management (particularly of hydro resources) and provision of operation reserves of different types (cold, tertiary, secondary and primary reserves). It is necessary to distinguish between the three dimensions of the reliability problem: *security*, *firmness* and *adequacy*:

- By security, we understand the readiness of existing generation capacity to respond, when it is needed in operation, to meet the actual load (a short-term issue). Security typically depends on the operating reserves that are prescribed by the System Operator.

- By firmness, we name the short-term generation availability that partly results from operation planning activities of the already installed capacity (a short to mid-term issue). Firmness depends on short and medium term management of generator maintenance, fuel supply contracts, reservoir management, start-up schedules, etc.

- By adequacy, we mean the existence of enough available capacity, both installed and/or expected, to meet demand (a long-term issue) [1].

It is widely agreed that the System Operator can deal with the difficulties of security using *ad hoc* markets. Nevertheless, there is not such a consensus about how to assure that the volume of installed capacity is sufficient to provide with an acceptable service.

1.1 The power market failure

In a competitive market where demand responds to prices, microeconomic analysis of a power system shows that, in the absence of economies of scale in generation, the resulting market price is sufficient to remunerate the total costs of those generating units whose investment is well adapted to the existing demand and to the existence of the remaining generation plants. This complete cost recovery condition applies to all generating units if each one of them meets the preceding condition.

Note that the peaking units do receive a revenue that allows them to recover their fixed costs, since these generating units may bid a price above their variable cost when no other less expensive available units may displace them. This price will be as high as the consumers will permit by reducing their consumption until the usual equilibrium of

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[1] A forth dimension could be taken into consideration, namely the *strategic energy policy*: the concern for the long-term availability of energy resources: physical existence, price, energy dependence of the country, reliability of the internal and external energy resources, potential environmental constraints, etc. (a long to very long term issue).

supply and demand is reached, so up to this point, then, there appears to be no cause for concern whatsoever.

This ideal situation where supply and demand always reach an equilibrium and therefore define an unambiguous market price, which results in complete cost recovery of all well adapted production units, requires a number of conditions to be met, which is usually not the case in practice, due to several actual reasons, such as price caps affecting the income of peaking generating units or the possible influence of mandatory levels of operating reserves in depressing the energy prices.

However, it would be possible to conceive of an advanced electricity system where, if prices rise too high, consumers may financially hedge themselves from prices higher than a certain ceiling. If the price cap were eliminated, their counterparty (typically the generator) would be exposed to a very high financial risk which would constitute a strong incentive to have enough energy available to hedge against such contingencies. Risk-averse generators want to protect themselves against low price scenarios and tend to install less capacity than if they were risk-neutral. Risk-averse consumers, on the contrary, want to protect themselves against high prices, and would therefore prefer a system with greater capacity than they would in principle prefer if they were risk-neutral. Therefore, if long-term agreements were executed between generators and consumers would see their risk of high prices decline, what would enable them to pay for the level of capacity preferred. At the same time, the generator's exposure would be reduced, and peak-load generating unit construction would attract investors.

Therefore, it would appear that if price caps were eliminated, a long-term market would spontaneously arise that would supplement the spot market and solve the problem. Unfortunately, real demand is not playing this role. Regulated rates preclude the need for protection against high prices and even consumers initially exposed to spot market prices

ignore reliability when making their decisions. There is a certain implicit assurance that leads consumers to believe that the regulator will never allow supply shortfalls or inordinately high prices that would jeopardise their interests. Therefore, demand does not respond suitably on the long-term market.

It does not suffice for demand to be elastic in the short term. In the event of a critical situation, the generators exposed to risk would be willing to pay consumers for disconnecting and the latter would accept the price if they deemed it sufficient to compensate them for outages. This would avert the possibility of shortage of supply, but would not eliminate high prices nor, therefore, consumer discontent. Short-term demand elasticity is normally a very expensive way of fostering adequacy of supply, especially because of the existence of risk aversion. The need for a new peak-load generating unit would, therefore, inevitably arise. Consequently, any acceptable solution calls for implementing measures that reduce peak-load plant risk.

If it is assumed that a market-based regulation is not able to provide with enough generation capacity without any regulatory intervention, the solution for the problem necessarily involves developing additional mechanisms to assure adequacy of supply. That was the case of Spain, where a capacity payment method was designed and implemented, although there has been a deep debate about whether these payments are effective.

1.2   Objectives and roadmap

The aim of this paper is to develop the alternative procedure that the 'White paper for the reform of the regulatory scheme of the power generation in Spain' proposes to improve the current Spanish mechanism. These improvements are aimed at guaranteeing at least a minimum capacity reserve margin, as well as at providing a strong incentive for generating units to be available when needed, that is, when supply is likely to be

insufficient to meet demand. An additional gain of the implementation of this method would be a reduction of the pressure on any required market power mitigation and supervision measures, which is certainly a significant advantage in the Spanish case. The current approach will be reviewed in section 2, highlighting the mechanism of capacity payments that has been in force in Spain since 1998 and its weaknesses. Afterwards, the alternative proposal will be fully described in section 3. Finally, the conclusions of this paper are summarized as the conclusions in section 4.

2   THE CURRENT APPROACH

2.1   Basic measures of the Spanish approach to enhance security of supply

Besides de capacity payment mechanism that we discuss later in this section, the Spanish regulation comprises several procedures aimed at tackling the adequacy problem. Several reports on reserve margin and electricity and gas grid planning procedures are compiled by the System Operator, the Energy Commission and the Industry Ministry. This information is useful not only as a diagnostic of the situation to take regulatory decisions, but also to advice agents in their investment plans. Nevertheless, the calculations made are too simplistic and could be considerably improved by introducing probabilistic and risk failure analysis techniques. In addition, what should be the required reserve margin and how to calculate it are still questions under discussion. As reserve margin is a potentially ambiguous concept that depends on the firm capacity definition, it should not be the general criterion used. Loss of Load Probability (LOLP) should be used instead, choosing a firm capacity definition that really reflects the probability of a unit being generating when it is needed, and a reserve margin calculation that returns results similar to the ones provided by the probabilistic model.

The administrative authorization procedures for new capacity play a vital role in the adequacy problem, as they introduce important delays in the process that have an entrance barrier effect. Increasing the human and technical resources in charge of the authorizations would have its cost fully offset by the resulting improvements on market functioning. Some additional measures could be considered, like requiring the central promoter to place an endorsement at the time the authorization is requested, which would be returned when the central is built. That would eliminate some requests and alleviate the work charge for the administration.

As stated in the introduction section, further than these very basic measures just described, there is no consensus about the suitability of the possible regulatory mechanisms aimed at guaranteeing adequacy of supply. The main instruments used with this purpose are first briefly reviewed, to focus afterwards on the discussion of the current Spanish particular approach.

2.2   Existing regulatory mechanisms to enhance reliability of supply

International experience has resorted to several procedures to tackle the problem of guaranteeing adequate reserve margins.

Licitations. European directive 54/2003 allows member states to carry out energy licitations and assign long-term contracts to the awarded generators. The Brazilian energy auctions (Bezerra 2006) appears to be turning into a reference design in Latin America (followed for instance by Peru).

Capacity payments, which were first used in Chile in 1982 and later adopted in Argentina, Colombia, Peru and some other Latin American Countries, under various formats, and also in Spain. In essence the method consists in awarding to each generating unit a daily payment (only when it is available) which is computed by multiplying the firm capacity of each generating unit times a per unit capacity payment

(€/MW) that may be uniform or may vary with the season. Each country has chosen a different approach to determine the firm capacity of the generating units, but the basic idea is that the firm capacity is a measure of the contribution of each generating unit to the reliability of the power system. Frequent conflicts have arisen because of the rules of definition of firm capacity of hydro plants and also of different technologies and vintages of thermal plants.

Capacity markets, which impose consumers –or their representatives- the obligation to acquire in the market a firm capacity equal to their demand plus a certain reserve margin. At the same time, the firm capacity of each generating unit is determined so it can bring its bids to the market. This approach was implemented in some U.S. markets, like New England or PJM.

Reserve markets. They consist in acquiring in advance an energy block with the commitment that it will be available when the remaining system capacity has been used, ensuring a certain supplementary reserve. They were recently implemented in Sweden and Holland.

As stated below, the approach chose by Spanish regulation is moderately interventionist and has opted for a capacity payment based method. A global perspective of the procedures adopted by the Spanish system is described next.

2.3   Key weaknesses of the Spanish capacity payments mechanism

The current mechanism of capacity payments ("garantía de potencia" is how it is called in Spain) consist in awarding generating units a daily capacity payment (only when they are available) that is computed by multiplying the firm capacity of each generating unit times a per unit capacity payment (€/MW) that is regulatorily determined. This payment involves certain obligations, as generating at least 480 hours per year to prove their availability or having certain strategic fuel stocks at their disposal. This mechanism is

expensive and has significant weaknesses that can be summarized in two: it does not provide generators with an incentive to make a special effort to be available and producing electricity when there is a real need for it and it does not guarantee that there will be a reasonable volume of installed capacity to meet demand at all times.

2.3.1 Absence of a well defined product

The mechanism implies that generating units receive a payment in exchange for almost nothing. If a generating unit happens to be unavailable in a day when there is not enough supply to satisfy the system demand, it just losses the capacity payment corresponding to this particular day, what represents an extremely small proportion of the total amount to be earned for the whole year. It can be therefore stated that the mechanism does not represent a special incentive for generators to really provide reliability for the system. Only the energy prices, potentially high when the reserve margin is tight, provide an incentive to be available whenever the system is close to rationing.

Therefore, there is no product from the generators' side, just a small incentive and no commitment to provide the assigned firm capacity when the system is close to scarcity. Besides, this scheme forces the regulator to supervise the availability status of each power plant very closely, since there is an economic incentive for the generator to declare as available a non-dispatched power plant, regardless whether it is available or not.

Moreover, the firm capacity to be taken into account for this payment is calculated following an extremely crude and arguable procedure: multiplying an average availability rate times a capacity value that, schematically, is the installed capacity for thermal units and the energy produced in an average year for hydro plants. A more sophisticated procedure would discriminate hydro plants with large reservoirs from those without, or even consider additional aspects such as environmental constraints of certain

thermal plants (e. g. SO2 or NOx limitations) or the firmness of the fuel acquisition contracts. However, there is not yet a consensus in the literature about an adequate model to calculate the actual firm capacity of the different (and diverse) power generating plants technologies. At the present stage, it seems advisable to be wary about moving towards more sophisticated algorithms.

On the other hand, the current criteria that are followed to make sure that the plant is able to contribute to the reliability of the system are very questionable. In particular, the requirement to produce at least 480 hours per year to have the right to receive the payment interferes with the market functioning, forcing a set of expensive plants to generate when they are not needed.

Moreover, the fact that a generator will loose the payment if it declares its unavailability creates an incentive not to be truthful in its declarations; regarding that bidding high enough to be excluded from the dispatch results more profitable.

The strategic fuel reserves condition can also be subject to conflict. The experience shows that the requirement to have at the generator's disposal an alternative fuel and a prescribed stored volume to prevent scarcities is difficult to supervise. In a broader sense, from the point of view of reliability, the way the gas procurement is managed in the case of combined cycle gas turbines can pose some problems. For example, a generator might decide not to operate so that it can sell the gas in the international Liquefied Natural Gas market or it might decide to tighten its reserve margin, in such a way that if for instance a boat is delayed (e. g. due to a storm) the generator would be subject to a energy limitation that might lead to a non reliability compliance if the critical scarcity period lasts more than a few hours.

2.3.2   No adequate reserve margin guarantee

The second regulatory flaw that has to be faced is that, although in a limited extent the capacity payment backs new investments by introducing an additional remuneration, it is not possible to ensure that it will be sufficiently appealing for the amount of them required to hold the desired capacity margin.

The security of supply mechanism in force in the Spanish market has been effective to prevent certain old installations from retiring. These plants were expected to be into operation very rarely, although their contribution to the system reliability in emergency periods was (and in certain moments has indeed been) crucial. Nevertheless, it does not look like that this mechanism has been behind the rather numerous new plants that have decided to get installed in these recent years. The regulatory uncertainty related to the capacity payments has reduced significantly the efficacy of the mechanism as an attractor for new investments.[2] Although the initial value was notably high, the perception that the Government ("the regulator" from this point on) can often and unexpectedly modify it has overshadowed the desired long-term investment signal.

As a result, if the regulator's purpose is to assure a certain level of investment margin, a new methodology has to be put in place. These weaknesses are tackled by the proposal of an alternative mechanism, which is described in the next section.

3   PROPOSED MECHANISM

The alternative procedure we propose in the White Paper and develop in this paper tries to overcome the described flaws and really guarantees an adequate reserve margin. The

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[2] The total volume of the payments has evolved from an initial value of 7,8 € per each MWh of the system load in 1998, to 6,9 €/MWh a few years later and finally to 4,8 €/MWh from year 2000.

fundamental criteria taken as a starting point, as well as its detailed development and discussion, are presented in this section.

3.1   Fundamental criteria

As mentioned above, relying on a healthy reserve margin is a key element for the correct development of a market, which should lead to turn it into the appropriate tool to provide the required incentives for generation and demand to maximize the overall system efficiency (and therefore the net social benefit). The credibility of the market price, i. e. the success of the price as the efficiency signal, free market barriers and uncompetitive behaviors, will be a critical factor in facilitating the entry of new investors and this, in turn, will help in maintaining this desired margin of the installed and available generation capacity over demand at all times. If this is the case, the situations where the margin is so tight that the price can be easily manipulated will be very rare, which is also helpful.[3]

Most liberalized electricity systems, the Spanish one among them, have opted for implementing some kind of specific security of supply mechanism, although it does not yet exist a clear consensus on which is the more reasonable design.

The most appealing option for us, and the one that has being recently proposed for several markets, is the reliability options mechanism. This scheme was first sketched in Pérez-Arriaga (1999)[4], discussed in the context of a regulatory reform in Argentina late in 1999, then proposed by the authors of this paper (also later by others) for the

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[3] Obviously, an active participation of the demand in the market will be a powerful factor of mitigation of market power. Unfortunately, the involvement of the demand has been scarce so far in actual electricity markets.

[4] In Pérez-Arriaga (1999) and Vázquez (2001) what we now call "reliability options" were named "price risk-hedging contracts" and "call options", respectively.

Colombian market, fully described in Vázquez (2001), Vázquez (2002) and formerly developed in deep detail in Vázquez (2003), as well as by Chao (2004) and Oren (2005) in the U.S. context.

The reliability options mechanism establishes an organized market where the regulator requires the Market or the System Operator to buy in a public auction a prescribed volume of contracts from generators on behalf of the demand. These contracts allow the consumers to obtain a price cap on the market price in exchange for a fixed remuneration for the generators. Additionally, the consumers obtain a satisfactory guarantee that there will be enough available generation capacity whenever it is needed. Otherwise the generators will be penalized. The generators are compensated economically for this service. Although the compensation per unit (MW) of firm capacity is uniform, the more reliable a generating unit is the higher is the economic margin that the generating unit obtains from the option contract.

In more precise terms, the commitment of a generating unit winning the auction is as follows: the generating unit sells, in exchange for a premium a call option for all the energy that its firm capacity can produce, at the strike price of the option, and it is subject to a prescribed penalty if the power is not delivered when required.

Therefore, this mechanism determines both the common per unit capacity premium and the firm capacity that is committed by each power plant through a competitive auction. However, when developing the actual implementation of the mechanism for the Spanish market, there are two basic elements that justify the use of a modified version of the reliability options that may be better suited to the particular structure of the market in Spain.

On the one hand, one should be aware of the convenience of developing a gradual reform, avoiding an abrupt change in the remuneration of the generating units that will

affect what it is supposed to be a long-term economical signal. Therefore, our proposed reform of the reliability mechanism should try to maintain, for the equipment already existing by the time the reform is implemented, an investment cost remuneration equivalent to what they would had received under the old capacity payments. We shall modify the existing capacity payments, aiming at including some operational incentives for these plants, but we shall make a specific treatment of these existing generating units in order to ensure as much as possible that their payments are not significantly modified. On the other hand, the Achilles' heel of the reliability options scheme is the potential for market power that can appear in the capacity auction. As in any other market-driven mechanism, there are many advantages in letting players express their valuations and preferences, but there is also a risk for manipulation if the players are few. When buying the options this risk is particularly high, since probably all of the existing units will be required and also some new additional ones. The workability of the mechanism depends critically on the ability of the auction to attract several potential new entrants and on the role of the incumbents. Being the latter a concern for us -the Spanish market is still rather concentrated-, some specific modifications of the reliability options are proposed in order to mitigate this problem.

Summing up, we are devising a kind of intermediate solution between the existing capacity payments and the ideal reliability options, that can be seen as a rational transition towards a fully market-based methodology, as it could be the reliability options market. Compared with the present mechanism, the proposed scheme introduces specific improvements addressed to guarantee a minimum margin of installed firm generation capacity over peak demand, and also to provide a strong incentive for each generating unit to be available and ready to produce at any time where it is really needed to meet the demand. This has the double purpose of improving the security of supply of

the system and also to maintain a healthy margin of generation over demand at all times, so that the potential of price manipulation is decreased.

In brief, the basic recommendation is to maintain the existing capacity payment format, consisting in a regulated remuneration to the generating units according to their firm capacity (assigned administratively as well and agreed with the generator, which could initially ask for a reduction in case it might consider the pre-assigned value to be excessive, particularly in the case of hydro plants). However, we propose to add some new elements that can be summarized in two: on the one hand, the commitment of each generating unit to provide its assigned firm capacity whenever the system is close to rationing, in such a way that a heavy penalty must apply to dissuade non compliance; on the other, in case the market (with the capacity payment) does not provide a prescribed minimum margin of installed generation capacity over demand, an auction should be run to attract the desired new capacity and to determine the value of the capacity payment that will be applied transitorily to any new entrants. These two elements are further depicted in sections 3.2 and 3.3.

3.2   A commitment in exchange for the capacity payment

The main proposal considered is completing the current mechanism in such a way that it allows to measure to which extent the awarded capacity is available when needed, as well as establishing high penalties associated to its unavailability. This enables to make agents responsible for the intermediate measures necessary to comply with their obligations, like fuel acquisition and hydro reservoirs management. As a result, it would not be necessary to monitor availability explicitly and inefficient rules as the obligation to produce at least 480 hours per year would become unnecessary.

Nevertheless, liberalizing this part of the process does not prevent the regulator from developing actions that impede clearly imprudent behaviors as safeguard measures to

avoid potential failures. For example, the regulator should not assign capacity payments to a plant that does not have an *Access to the Network contract* or that is affected by a local NO_X emissions limit that does not permit it to generate energy under every circumstances.

How to determine the near-rationing conditions when the commitment to produce would be active, as well as the basic mechanism of the capacity payments, will be further discussed below. Before entering into more detailed discussions, we first present briefly the basic scheme of the mechanism.

3.2.1 Basic scheme

For the already existing generating units, the proposed procedure is structured as follows:

-   A firm capacity value is administratively assigned to each generating unit, which can choose to reduce it in case it estimates that the risk of not meeting the commitment and being penalized is too high.

-   A regulated payment per megawatt is established.

-   It will be considered that the system is near-rationing whenever the energy price in the spot market is above a certain threshold. Under these conditions, the generating units that are awarded a capacity payment are committed to produce at least their firm capacity.

-   In case they do not fulfill this requirement, they will be penalized for each non-supplied megawatt.

-   In any case, if the price is above the threshold, the generator has to return the difference between the market price and the determined threshold.

3.2.2   Defining the obligation

Spot price has been chosen as the best available indicator to reveal critical situations. More specifically, the near-rationing conditions are identified when market prices are higher than a certain percentage above the operating costs of the peaking technology. Given that this constitutes an *ex post* measurement, the units are forced to identify in advance the conflictive hours. This is clearly a risk for generators, but it is acceptable as they are able to manage it appropriately and this procedure eliminates possible distortions introduced by *ex ante* previsions.

An alternative could be using some other measurement of reserve margin made by the System Operator. Nevertheless, such a measure would certainly imply a certain degree of arbitrariness. The existence of this arbitrariness is undesirable when there are implicit economical consequences, and can lead agents to question the System Operator's decisions. As a result, this approach is not recommended but could be taken into account if future experience advices to do so.

With the aim of assuring that the threshold, determined as a certain percentage above the operating costs of the peaking technology, is a reliable indicator of critical situations, it is necessary to take two issues into account. Firstly, demand should fix the market price. For example, if the System Operator interrupts supply to certain costumers (foreseeing capacity problems) before market settlement, this action should have economical implications on the market price. A regulatory price for interrupted demand has to be determined, and this price should be considered as an offer into the market so agents can perceive that the system has problems when these high prices arise.

Secondly, the obligation for generating units under near-rationing conditions involve that they should compulsory present a program to the System Operator in which they will be producing at least their firm capacity during the critical hours. They can comply with this

obligation both through bids to the spot market and bilateral contracts. The generating units that were not dispatched become exempt of their firm capacity responsibility, which is helpful for generating units with excessively low reaction times. In addition, all energy purchased in shorter term markets (intradaily or ancillary services markets) should pay also the penalty associated to capacity payments. This rule impedes undesirable behaviors as having some generators selling their energy to the daily market and buying it back in the subsequent markets to avoid the penalty. In addition, it enables to detect problems in the daily time horizon and not afterwards.

An additional consideration is that meeting demand is not enough, as some reasonable levels of secondary and tertiary reserves are also necessary. The price in the daily market could be acceptable at the same time that it reaches very high levels in the reserve market. A possible approach to face this problem would be to define different categories of reliability options for the daily and the reserve markets. However, this would mean additional complexities and will therefore not be taken into account in a first approach.

3.2.3 Determining the penalty

The penalty is intended to dissuade agents from not complying with their firm capacity obligation. Thus, it should be high enough to have economical consequences. Moreover, it should be potentially higher than the original total capacity payment as, if it was not, generating units would be willing to be assigned a large firm capacity because, in the worst case, the payment would still compensate the penalty.

The value of the penalty should not imply excessive risks for a peaking unit with a reasonable failure rate. For example, assuming that price can stay above the determined threshold for about six to eight hours, then a generating unit should loose all the yearly payment if it fails to be available that time period. Therefore, the penalty should be

calculated dividing the total payment per megawatt by the eight hours defined as a reasonable reference.

To avoid excessive penalties in particularly problematic years, the hourly penalty value can be affected by a correction factor that decreases with the amount of hours for which a generating unit is penalized.

As a final consideration, it should be noticed that the unitary capacity payment should incorporate the expected penalty value for an efficient plant.

3.2.4 Setting the threshold

As stated below, this threshold should be above the operating costs of a reasonably efficient peaking unit. With this purpose, it is necessary to assume a certain operating regime, as start up costs can have a relevant impact on this level.

In addition, the considered threshold should be revised periodically. It would be suitable to establish clear indexation rules that would determine its future evolution.

3.2.5 Defining the unitary capacity payment

The regulated capacity price should consist of two components: A considerable percentage (but not the complete amount, for example an 80%) of the fixed cost of a gas turbine, as it is considered the peaking technology. The more similar the threshold is to the operation cost of this technology, the more similar this component should be to the total fixed cost, and also an estimation of the expected total penalty that generators should return to the demand.

3.2.6 Assigning firm capacity

This value, as stated below, should be administratively calculated and assigned to each generating unit. Therefore, it is advisable that the procedure used is as simple as possible.

Groups with no energy constraint would be assigned their nominal capacity regardless of their fuel acquisition contracts. Energy-constrained generating units (namely, hydro units) would be assigned an estimation of their average production in the n most peaking hours of the last 5 years. An extended proposal could consider setting more than a single value for hydro groups, typically distinguishing between summer and winter capacities in such a way that both their income and obligations depend on the season. This measure could provide them with more flexibility in their capacity management, but probably implies the duplication of the whole system with two seasonally different capacity payments. Therefore, it should only be adopted if it is strictly necessary.

This proposal considers that some renewable generating units like wind or solar groups are currently unable to manage adequately their capacity risks, so they should be excluded from the mechanism. Nevertheless, the System Operator should estimate their average contribution for its reserve margin analysis.

The administratively determined value could be modified by generators (but just to decrease it) in case they perceive their incompliance risk is too high. However, a minimum level should be established (for example, 70% of the initial assignment), since an excessive reduction of these values might leave the system in a weak condition from the point of view of security of supply, or even to prevent situations in which generators could be interested in forcing an auction for new entrants (see section 3.3)

3.2.7   Portfolio bidding

Initially, it should be noted that portfolio bidding would discriminate agents, favoring the largest ones, as a large company could more easily substitute a failed generating unit by another one. However, penalizing a company for one of its generating units when its portfolio has globally fulfilled its obligations seems perverse.

This disadvantage could be overcome by organizing a secondary capacity market, so generators can equally resort to it to avoid the penalty. Nevertheless, and due to the difficulties of creating such a market, this proposal does not contemplate it at least, until market is mature enough, and advises to assign firm capacity to each generating unit individually.

3.3   Guaranteeing an adequate reserve margin

The second flaw of the current capacity payments mechanism is that, as stated below, although it introduces an additional remuneration that supports new investments to some extent, there is no guarantee that it will be enough to attract the required amount of generating units. Experience suggests that these payments have been successful just to persuade obsolete generating units to stay in the system, but not to stimulate new investments. Therefore, it is necessary to introduce an additional procedure that allows the regulator to achieve its installed capacity goal.

The Directive 2003/54/EC of The European Parliament and the Council of the European Union (2003), in its article 7.1 states that 'The Member States shall ensure the possibility, in the interests of security of supply, of providing for new capacity or energy efficiency/demand-side management measures through a tendering procedure or any procedure equivalent in terms of transparency and non-discrimination, on the basis of published criteria. These procedures can, however, only be launched if on the basis of the authorization procedure the generating capacity being built or the energy efficiency/demand-side management measures being taken are not sufficient to ensure security of supply'. On the other hand, the Spanish Electric Power Act, CNE (2005), in its article 10 reads 'The Government may, for a certain period of time, adopt the necessary measures to guarantee the supply of electric power whenever any of the

following circumstances arise', among which it includes 'A definite risk for the provision of the supply of electric power'.

Generally, the solutions that are often considered under these circumstances imply very long-term contracting (of the traditional kind that is known as "power purchase agreement" or PPA contracts, involving the payment of fixed and variable costs) that considerably interferes in the short-term energy market, as in California, EIA (2005), Brazil, Bezerra (2006) and Peru, Cámac (2006). The proposed mechanism is expected to interfere much less. The main idea consists in allowing the regulator to call an auction when it has detected a problem of underinvestment. The auction would determine the value of the capacity payment that will be applied transitorily to any new entrants. Otherwise, both the existing and the new entrants function in the energy market in the normal way.

One of the positive characteristics of this design is that the auction just affects a small number of generating units, while the capacity remuneration of the majority remains regulated, and essentially, not involved in this new capacity market, thus reducing the potential market power interference, and therefore avoiding certain types of undesirable games that might appear. Again, we first depict briefly the basic scheme of this second aspect of the proposal, followed by a more precise description of the main issues that should be taken into account.

3.3.1 Basic scheme

The basic scheme of the proposed mechanism is:

- The regulator, supported by the System Operator, supervises if there is enough investment announced in the system for a prescribed time horizon (the lag period, see below), taking into consideration the existing generating units as well as the expected

(and confirmed) new entrants and plant closures, and checks if the expected reserve margin for this term is suitable enough.

- If there is not enough upcoming investment, the regulator runs an auction for the amount of needed capacity. The participants in this auction can be the potential new investors as well as those installed generating units that are less than five years old (the binding period, see below) and have not won any previous capacity auction.

- The auction winners assume analogous capacity obligations as the ones already adopted by existing generating units. This commitment is effective after a lag period (three years) and its maturity is no longer than the binding period (five years). More specifically, new generating units assume the responsibility for five years, while already existing generating units accept it until five years are passed from the moment they were installed. In exchange, these generating units earn the marginal capacity price resulting from the auction during the time their obligation lasts.

- Once the five years binding period is over (or the five years minus the time since the generating unit got installed, for the case of the existing generating units), the winners of the auction receive the regulated capacity payment like the rest of the already existing units.

3.3.2   Types of generating units

Except for the capacity payments, all plants operate normally in the wholesale market and receive the energy market price. *Ad hoc* additional rules are needed so that potential new investors do not find it advantageous to wait until the auction is called, therefore forcing any new investment to happen only via the auction. For instance, a new entrant receives the standard capacity payment but, if an auction is run within five years of its date of entry, it receives the capacity payment that results from the auction for the remaining time. According to this, we can distinguish three kinds of generating units.

- The existing units, namely those installed before this mechanism is implemented or those that have already won any previous auction and which binding period has already expired. These generating units do not take part of the auction, so they do not provide any incentive for the utility to raise capacity auction prices to get higher profits.

- The generating units already installed (and not older than five years old) that have not yet had the chance to play a part in any previous auction. For the time being they receive the standard capacity payment. These generating units can still be considered as "new" and therefore they can take part in the auction, earning the marginal capacity price resulting from the auction until they are five years old. From this point of time on, they are paid the regulated default value.

- The new generating units, that is, the ones that, at the moment that the auction is run, are not in the system yet. These agents can participate in the auction, subject to the formerly described conditions.

3.3.3   Auction terms

The obligations will not be active until a lag period of three years has passed. This time period should be enough for a generating unit to get installed and ready to produce. Obviously, in order to start building the plant immediately after winning the auction, it would be necessary that the promoter already had all the required licenses. As these administrative procedures are quite time consuming but do not suppose a considerable monetary risk for investors, it will be assumed that all the licenses are obtained in advance. Extending this lag period would be more risky, as it would imply a higher uncertainty about future power market evolution.

The capacity responsibilities are assumed for a five year period. This is long enough to be significant to justify investments. Spreading it out would mean again higher risks for generators, as the obligation implies a commitment to produce firm capacity.

3.3.4   Auction procedure: quantities to be bought and prices

The System Operator will call an auction to buy the difference (if positive) between the maximum expected demand plus a reasonable reserve margin and the firm capacities of the existing generating units as well as the expected (and confirmed) new entrants and plant closures. The contributions of renewable generating units and interruptible costumers are also taken into account.

All the winner generating units will receive the marginal price resulting from the auction. This auction clearing price (i. e. the new value of the capacity payment for the new entrants for five years) is bounded: a lower limit is determined by the standard regulated payment that the existing generating units already receive and an upper limit represents the maximum payment the system is willing to pay, i. e. a price such that it is considered that it is worth having less installed capacity than paying for it. The objective of setting this upper bound for the price is to avoid potential market power abuses in case the auction might not be liquid enough. If the lower limit, that is, the standard regulated capacity payment, is set to 80% of the reference investment cost, the maximum price could be set at 120% of this value.[5]

An additional consideration about the quantity to be bought is that it seems rational to establish a certain demand curve. For example, it could evolve linearly between the minimum and maximum prices as determined above considering a higher reserve margin

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[5] In theory, this latter value should be enough to fully finance a peaking unit, even if it would never operate. Therefore, bids at higher prices would reflect either a wrong estimation of the regulator or market power abuse behavior.

if price is the minimum (for example, 15% for the minimum price and 10% for the maximum acceptable price).

3.3.5 The case of lack of auction contestants

An additional and critical aspect is what to do in case the firm capacity that is offered at lower prices than the upper bound does not reach the required level. It does not seem acceptable that the System Operator may decide to increase the upper bound for the bids in the auction or to buy capacity outside the auction at a higher price. To prevent this situation from taking place, we propose a two-step procedure, which is inspired in the British radio station auctions, Binmore (2002), and which has been a reference also for the Brazilian energy auctions we formerly referred to.

First, the agents are asked just for quantity bids, assuming that all of them will be willing to commit themselves to fulfill the reliability obligations at a price not higher than the predetermined upper limit. If the volume of total bids is satisfactory, the regulator proceeds to a second round in which the agents are asked for prices.

However, if the total volume is insufficient to guarantee a competitive auction outcome, then the original bids are frozen for a period of a few months, and a second round of the auction is widely announced, aiming at attracting new entrants. The idea behind this procedure is that most potential investors do not present bids in every market in the world, since it would be rather time consuming and their chances to win in each one of them appear to be quite slim. Whenever there is a lack of bids and therefore a high price can be expected, it is likely that some additional players will join the second round of the auction.

4   CONCLUSIONS

The proposed procedure improves the current capacity payments mechanism regulation since it provides, on the one hand, a valid incentive for generating units to be available when they are really necessary and, on the other hand, a real insurance against underinvestment scenarios as well as price spikes.

It introduces the idea of requiring the generating units subject to the mechanism to supply their firm capacity in tight reserve margin conditions. These problematic situations are defined as the time periods when the spot market price lies above a certain threshold, which is determined as some percentage above the operation costs of the peaking technology. In these cases, the generating units should be producing at or above their firm capacity and would not perceive a price higher than the defined threshold.

With the aim of persuading generators from not complying with their capacity obligations, the penalty incurred should be designed to have considerable economical consequences, in particular, to have the potential for being higher than the total yearly payment.

The unitary capacity payment takes into account the expected penalty for an efficient generating unit, and is based on a considerable but not complete percentage of the fixed costs of the peaking technology –the more similar the threshold is to the operation costs, the higher this percentage should be - .

In the cases when there is not enough capacity to cover demand plus a reasonable reserve margin, the System Operator will call an auction that would determine the value of the capacity payment that will be applied transitorily to any new entrants. If there is a lack of contestants, the auction would be frozen and a second round would be widely announced so that additional players can join it.

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