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Security of supply in the Dutch electricity market: the role of reliability options

Report IIT-03-084IC

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Prepared for the Office for Energy Regulation (DTe) of The Netherlands

Madrid, December 15th 2003
Draft version 3.0

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Acknowledgments

This work has benefited from the previous experience of the authors in the reliability options mechanism, which originated at a research project developed for the Association of Electricity Generators of Colombia (Acolgen). Undoubtedly, the report in its present form has been significantly improved by the interaction with the DTe staff whose insightful comments and discussions have contributed to a number of relevant point in this draft paper. We are in debt with Gijsbert Zwart, Carel van der Lippe, Kees-Jan Kuijlaars and Rudi Hakvoort, from DTe, as well as with Laurens de Vries, from T. U. Delft, for their contributions. As usual, all remaining errors are ours.

1. Introduction

This document is the result of a joint collaboration between the Instituto de Investigación Tecnológica (IIT) of the Universidad Pontificia Comillas and the Office for Energy Regulation (DTe) of The Netherlands, and it is aimed to study how the reliability options approach for security of supply could be implemented in the electricity market in The Netherlands. The project is part of the effort that DTe is undertaking to identify solutions to the long term guarantee of supply problem in the Dutch power market, and starts from the previous experience of IIT in these issues.

During the last years of the current process of electricity liberalization, security of supply has increasingly become an issue of concern. Basically, the question under discussion is to determine whether a market-based regulation will be able to provide enough generation capacity in the system or not, and under which conditions an energy-only market will be enough to ensure system requirements for new investments under reasonable reliability standards.

A useful preliminary approach to answer this question is to discriminate among the two components of generation reliability: *security* and *adequacy*. By *security* we mean the readiness of the existing capacity to respond when it is needed during the operation time, in order to meet the actual load of the system. By adequacy we mean the existence of enough installed capacity, expected to be available when required, so demand can be met. Thus, the first one is a short-term issue, while the latter one has to do with long-term concerns. This distinction allows us to partly answer the initial question. In general terms, the markets seem to include enough mechanisms to guarantee a sufficient level of security in the system: the *ad hoc* markets for quantities of operating reserves that are organized by the TSO appear to be a good alternative, and a useful hybrid between market and regulation. On the other hand, long-term power system *adequacy* unfortunately remains as an open question.

The problem is especially critical since the consequences of under-investment for market performance are frequently dramatic —including very high prices and rationing—, and also considering that episodes with these characteristics have been appearing in the international experience more often than expected during the last few years[1]. Thus, it is interesting to analyze how an additional regulatory mechanism such as the reliability

[1] However, not all of the rationing episodes that have arisen lately are due exclusively to this factor. Although evidence is still incomplete, most authors point out that at least in the NorthEast U.S. blackout and in the Italian incident (both in 2003) a major part of the responsibility was due to problems in system operation, shortcomings in transmission infrastructures and in reserves procurement.

options can improve long term economic signals for investment and bring some solution to the present security of supply concerns.

The report first describes summarily in section 2 the basic elements of the reliability options method and its motivation —as they were before this project started (see [Vázquez *et al*. 02])— and which are supposed to be already known by the readers. Then, section 3 concentrates on the description of the implementation details of the proposed scheme, discussing several different alternatives and identifying the most suitable solutions for the Dutch context. Finally, a detailed procedure is presented in section 4.

2. Description

The label of long term guarantee of supply is used here to include all of the issues that are somehow related with the need to ensure that, in a market context, there will be enough installed —and available— generating capacity in the system to meet demand in the long run. The reliability options mechanism is one of the different methods that have been proposed to deal with this question. Along this section, we shall first try to identify the nature of the problem and to show the reasons why we think that there is a problem that requires some specific regulatory measure in order to facilitate a good performance of the market. The market failures that we shall identify will condition our analysis of the different solutions, so it is useful to have them in mind during the analysis of the proposed method. Then, we shall outline the basic features of the reliability options mechanism, which will be further discussed with much more detail in section 3.

2.1 Long term guarantee of supply

The changes in the regulation of the electric power industry worldwide have modified the traditional reliability issues and approaches drastically. In the vertically integrated utility, under cost-of-service regulation, reliability was seen as a major ingredient in the global exercise of centralized utility planning, at all levels: generation, transmission and distribution. Under the market-oriented paradigm, the new regulation must make sure that the appropriate economic incentives exist for each one of the activities so that quality of supply is maintained at socially optimal levels. This document only concerns reliability of generation, where the change has been more pronounced since in the new regulation the generation activity is fully opened to competition.

The issue under discussion is whether the deregulated activity of generation of electricity in competitive wholesale power markets does or does not need regulatory intervention in order to provide a satisfactory level of reliability of supply. According to basic principles of economic theory, if there is scarcity in electricity supply —or in the supply of any other commodity provided by a market— the price of the commodity will increase enough to attract new investment, as well as to encourage more production from the existing plants and to reduce demand from the consumers, until the normal level of supply and prices is reestablished.

This economic theory has been applied to electricity markets —see, for instance, [Caramanis 82] or [Pérez-Arriaga & Meseguer 97]— showing that the spot market itself is enough to provide adequate investment signals to encourage efficient entry. Thus, it seems that there is no need for any additional regulation for security of supply. The non-storability of electricity, that has sometimes been cited as a justification for a distinct regulatory treatment of security of supply is explicitly considered in this analysis and it is proved not to be so relevant.

However, in real markets there are some practical questions, especially the risk aversion of some participants, that prevent a straight-forward application of the theoretical results[2]. The case of a peaking unit may illustrate the problem. This unit only happens to generate a few hours per year and, as a consequence, it receives no remuneration most of the time and a high income in a few occasions. Since its average income is enough to recover capital costs with a reasonable profit, theoretically there is an economic signal for this generator to be in the system, but a risk-averse firm would feel this high income volatility as a too risky situation and it would decide not to install any new peaking plant. If the regulator or the consumers want this unit to enter the market, they have to provide either additional income stability to diminish the risk, or additional net revenue to increment the reward; otherwise the generator will not be there to produce when needed. This risk aversion can be considered as a peculiar characteristic of power markets —and also of most infrastructure markets— since electricity provision requires very large investments, the production plants take significant time to be installed and operational (this time has been very much reduced recently, with two years being presently a typical figure for the very popular combined cycle gas turbines) and have a long economic life (about thirty years or even more), and all of these issues make investment especially risky and make investors more risk averse than in other types of markets.

In an ideal market, consumers who may be willing to have a better level of reliability and thus want some more generators to enter the system, would sign long term contracts with generators (or at least with the peaking units) and provide them the income stability and/or additional revenues that they require. The reliability in the system would only depend on how much the consumers are willing to commit in these long term contracts and how much they are willing to pay for their security. Again, it seems that there is no need for any specific guarantee-of-supply regulation since, although the spot market presents some problems, the long term market does provide the proper incentives.

But we are seeing that real markets are not behaving this way. In most cases, consumers are isolated from the actual spot prices either by regulated tariffs or by average procedures to calculate the tariff so they feel no need for hedging against the risk of having high prices and they see no advantage in long term contracting. Even in the rare markets where demand is really exposed to the spot prices, long term contracts are not taking place either. Most of the consumers are not mature enough to realize the risks involved and in these cases they tend to make their decisions using only very short-run criteria. This lack of demand-side response creates a malfunctioning of the long-term market that cannot be solved in the short run, and it causes a lack of generation

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[2] Another relevant reason for this is the existence of price caps in the spot markets, which limit the potential gains that the generators that produce during the critical periods receive from the market, therefore diminishing the incentives for new investment. This can often lead to a level of investment that is under the desired reliability standards.

investment that paves the way for potential future shortages. Note that the need here is not just for consumers demanding less energy from the market when prices are high — this is the typical goal of demand-side management programs— but especially for having them signing efficient hedging contracts to express their need for a higher level of generation reliability (i. e., to express their risk aversion).

The most orthodox answer to this question would be doing nothing. Consumers would have to go through the high prices and the rotating blackouts (as it happened in California, for instance) and, the following year, some of them would realize the need for protecting themselves against this situation and would sign some contracts. The process would go on until consumers understand how to operate efficiently in the long term market. Unfortunately, this would probably be a long learning period, which may include several rationing episodes and, according to what we have seen until now, it is likely that it would be considered more a problem with the market than a problem with the consumers that are not acting efficiently. Electricity is an essential good, without an easy replacement in modern society; shortages of electricity have significant social and political implications, what makes politicians, regulators and system operators particularly aware of reliability of electricity supply. In most systems, and this was the case in California, the market rules would be dramatically changed before consumers have time to complete their learning process. The long term market would never reach a steady state because it would be completely refurbished much sooner. In fact, what is underlying beneath this movement is the principle that a wise regulator should not assign responsibilities to any individual that is not prepared to perform them adequately. And, nowadays, it seems that most of the demand is not prepared to deal efficiently with the problem of long-term generation reliability. Thus, some kind of additional mechanism is needed, at least as a transitory procedure, to guarantee that there is enough generation in the system to meet future demand. In other words, consumers do not feel completely the fear of very high prices when deciding their contracts since they know that "the regulator will not let rationing happen", so there is a kind of implicit insurance provided by the regulator that is interfering the long term market.

Solutions adopted in other markets include (see [Pérez-Arriaga 01]) the LOLP term in England & Wales, the capacity charge of Argentina, Colombia, Spain and several other countries, the capacity obligation of the Northeast-USA pools, the idea of the ISO buying the reliability-related generation facilities (i.e., the peaking units) that has been proposed in Australia, and the alternative of buying surplus operating reserves that is been explored in several markets, including The Netherlands.

2.2 The reliability options

One possible way of motivating the reliability options design could start from the idea of implicit insurance. When there is a security of supply problem, and prices for final consumers are high and shortages appear, the situation may become a very difficult political problem for the regulator. Consumers are also hurt but, as we have just seen, they do not react. So it is the regulator who should try to protect himself against this political risk, through a change in the market design. He would like to impose a price cap on the market, but this is a problem with the very old and inefficient plants, which may not produce even if needed if the price cap is very tight, and with the new entrants, which may be discouraged. In financial markets, a buyer who wants to get a price cap on his future purchases can acquire a certain kind of derivatives, known as a *call option*, which gives him the right, but not the obligation, to buy the item at a predetermined price (the strike price) in exchange for a premium fee. This is a way to obtain market-compatible price caps. Accordingly, we propose that the regulator should buy call options from the generators, probably through a centralized auction, and therefore isolate consumers from the high prices.

At the same time, the generator that is selling a call option is giving up receiving the part of the spot price that is above the strike price in exchange for the premium fee or, in other words, he is exchanging some uncertain and very volatile income from the spot market for a certain remuneration from the capacity market. In the case of a risk-averse peaking unit, this greatly reduces its risks and it is just the kind of deal that he is willing to accept in the long term. Thus, two main objectives are achieved with this mechanism: on one hand, consumers do not have to bear the risk of having high energy prices reflected in their bills; on the other hand, efficient economic signals for new investment are being provided.

The model can also be interpreted as if the market authority partially replaces the demand in the long term market and acts as a trader who is buying reliability contracts on behalf of the whole demand. Moreover, it can be considered that this proposal is just an enhanced version of the PJM market, but with a better definition of capacity, that now turns out to be a financial option. This is a generalization that provides much stronger incentives for reliability-oriented operation and eliminates the need for the regulator to calculate the “firm capacity” of each unit, which may be a capital advantage when there are energy-limited plants involved. Through these incentives, the markets bring the consumers a broader security that the contracted generation equipment will be available during the critical periods when it is more necessary.

Additionally, a physical delivery obligation is tied to the option, in order to provide stronger incentives for the generators and to make sure that the more reliable production units will be in a better position at the reliability market. This means that an option-selling generator that, when the prices are high, fails to provide the power he committed to produce has to bear an extra penalty for each megawatt non-delivered.

Summarizing, the procedure would be as follows (see section 4 for a more detailed version of these instructions):

- An auction is organized where the auctioneer has to determine, in advance, at least the following parameters:
  - the strike price, s: it should not be too low, since it acts as a price cap for demand and somehow represents the frontier between the "normal" energy prices and the "near-rationing" energy prices,
  - the time horizon: typically a year; the seller can be required to generate the committed capacity at any time during that period,
  - the total amount of power to be bought, Q,
  - the value of the explicit penalty, pen.
- The generators submit one or several bids to the auction, expressing quantity (the capacity they want to sell) and price (the required premium).
- The market is cleared as a simple auction and all of the accepted bids receive the premium that was solicited by the marginal bid.

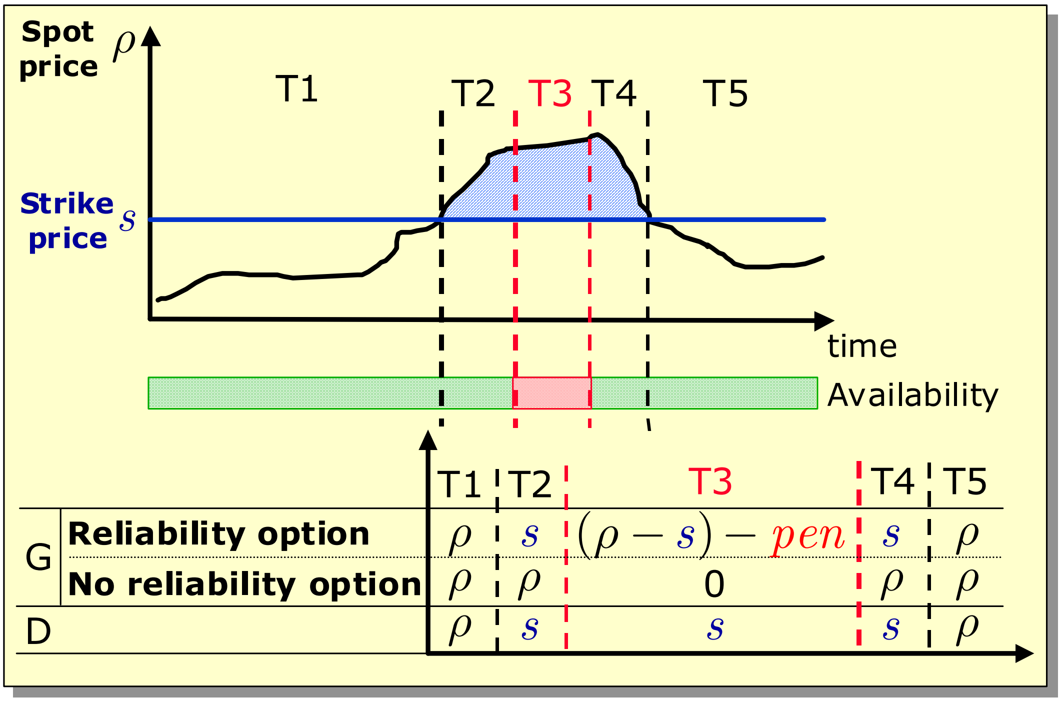

Fig. 1 The reliability product

- During the specified time horizon, any time the spot price ρ exceeds the strike price s, the bids that were accepted in the capacity auction will have to refund the regulator —and, indirectly, consumers— for the difference $(\rho - s)$ for each megawatt sold in the capacity market. Henceforth, we will refer to this refund as the "implicit penalty". Additionally, if the spot price is above the strike price and the production g of a certain generator is lower than the committed capacity q, then he would have to pay to the regulator an "explicit penalty", computed as $pen \cdot (q - g)$. An example of this is illustrated in Fig. 1.

3. Detailed analysis

3.1 Interaction with longer-term contracts

One of the most relevant differences between the Dutch market and the Colombian mandatory pool, for which the reliability options were originally designed, is that in the Dutch case trading takes place through a large set of different instances, which range from long term bilateral contracts to very short term transactions, including OTC markets, organized exchanges such as the APX and a large percentage of bilateral contracts. This means that there is no single pool where all of the energy is bought and sold, and that the implementation of the reliability options scheme for the market in The Netherlands has to take this characteristic into account when defining the obligations and rights that derive from the capacity mechanism.

Let us assume that a reliability options scheme is implemented and that the day-ahead market run by the APX is selected as the reference market (following the analogy with the Colombian mandatory pool) —this decision is discussed in depth in section 3.2—. Thus, any generator that is awarded some capacity in the reliability auction will be selling some amount of capacity in the form of reliability options and, every time the price in the APX rises above the strike price, he will have to refund the difference between the spot price and the strike price. And, also, if he is not producing by that time, he will have to pay an explicit penalty for the energy not made available. This provides a strong incentive for the option-seller generators to be producing at those moments —which is the aim of the mechanism— in order to avoid the explicit penalty.

However, this also creates an incentive to be selling the option-related energy at the APX day-ahead market whenever the price happens to be high. Selling into this market allows the generator to receive a high spot price at the moments when the options create the obligation to refund the excess of the spot price over the strike price, so that the net result of both transactions will be just a cap on the income received from the sale , equal to the strike price, but the reliability options obligation will not represent any explicit payment. This may not be very relevant in term of expected income —if the generator is not selling at the APX market when there is a price spike he will not capture the high potential income in any case, regardless of whether he has some reliability options or not—, but is relevant in terms of risk exposure. If a certain generator is producing when there is a raise in the price at the day-ahead market but he is selling his energy at some other market —for instance, he sold it six months in advance at an OTC market—, then he will not be punished with the explicit penalty, but he will have to pay the difference between the APX spot price and the strike price. This means that he is exposed to a price risk linked to the day-ahead APX market even if he is producing at the correct time. In other words, any generator that participates in the reliability options procedure would feel the need to sell its production at the APX market or, if he does not, he will have a loss when the spot price rises; he will be exposed to some risk associated to the APX price.

Therefore, the mechanism discriminates in favor of trading at the reference market, and this is a problem with the proposed design. There are several potential ways of dealing with this difficulty. As described below in section 3.1.1, if nothing is done the market participants on their own could adapt to the new situation and renegotiate the long-term contracts in such a way that the economic effects of the options do not harm the generators who have contracted. However, this would considerably change the philosophy of long term contracting in the market and, in general, it may imply major changes in market design that may be undesirable. Fortunately, it is possible to find an alternative way of dealing with the obligations derived from an option that solves the problem without altering so much the spirit of the Dutch market design. This is described in section 3.1.2 and it is also part of our final recommendations. Also, a different approach that is more heavily based on physical trading could be devised to cope with this issue, and it has appeared within the discussions held with the DTe staff. This alternative is roughly described and discussed in section 3.1.3, although we have not entered into much detail on it since we understand that it suffers from some implementation difficulties.

3.1.1 An inappropriate solution: redefining the contracts

If nothing is done, contracts will tend to be renegotiated in two different ways. On the one hand consumers, who know that they will be protected from the high prices by the reliability options that the regulator has bought on their behalf, will be willing to pay less for their contracts, since the price they would pay at the spot market is reduced by the effect of the option (see Fig. 2). Accordingly, they will be willing to engage into contracts only for their estimation of the prices in the day-ahead market that range from zero to the strike price, and they would not be worried for the prices above that level.

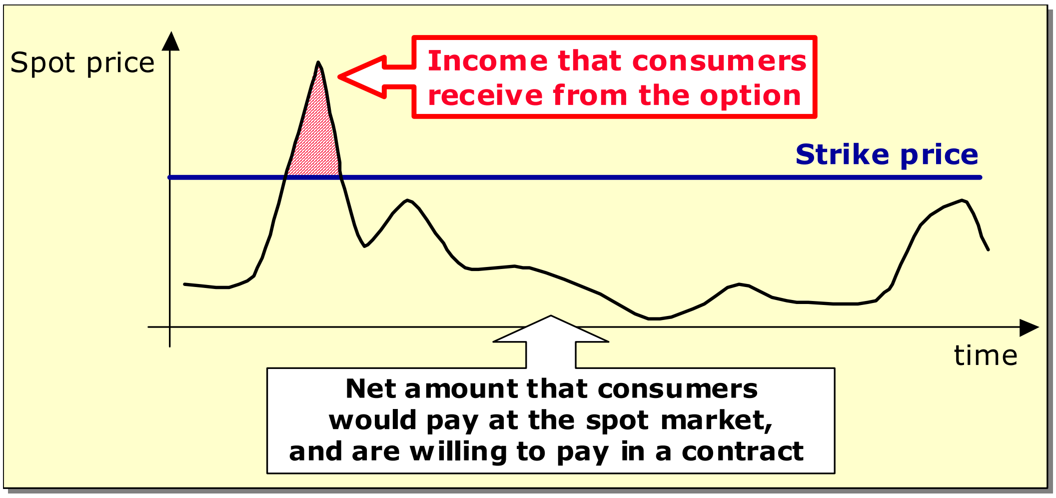

Fig. 2. Energy contracts

On the other hand, generators will require to transform these contracts into financial derivatives —contracts for differences— related to the APX market, in order to make sure that they will always sell their power into the APX. Thus, if there is a price spike at the day-ahead market, the generators will be selling at that market and receiving the high price, so it will not be a problem for them to refund the difference between that spot price and the strike price, as required by the reliability options.

Then, the payment scheme associated to the contracts would be as follows. If the price at the day-ahead market ρ is lower than the price determined in the contract c, then the consumer will have to compensate the generator for the difference $(\rho - c)$. If the price ρ is higher than c but lower than the strike price s, then the generator will compensate the consumer for the amount $(\rho - c)$, as in a typical contract for differences. If the price ρ is higher than s, then part of the difference between ρ and c is not covered by the contract, and the generator will only have to compensate the consumer for the amount $(s - c)$, according to the contract.

However, in this latter case, the consumer will receive the amount $(\rho - s)$ as a right associated to his reliability options, so his net payment would only be c: he pays ρ for the energy he buys, receives $(\rho - s)$ from the reliability option, and receives $(s - c)$ from the energy contract. This options-related source of income is what makes the consumer want to change his contracts and only relate them to the prices in the spot market that are lower than s.

From the generator's point of view, if he holds a reliability option he would have to pay an amount $(\rho - s)$. Thus, if he also holds a contract his net income would be just c, in an analogous way to the consumer's income. But he needs to be selling his energy at the APX in order to receive the whole spot price ρ in order to have enough funds to pay the implicit penalty $(\rho - s)$ without experiencing a direct loss.

With this solution, where contracts have been renegotiated to consider the effects of the reliability options, the generators avoid the price risk that appeared before associated to the APX price and therefore there is no punishment for contracting. However, this means that almost all of the energy in the system should be traded through the APX and this radically changes the way in which consumers and generators do bilateral trading nowadays. Although a contract for differences, such as the ones suggested in the previous paragraphs, has equivalent economic effects to a direct bilateral contract, such as the ones existing presently in the Dutch market, they both imply different market design philosophies and the guarantee of supply mechanism should not force such a change in the market paradigm unless strictly necessary. This is why the solution just described does not seem acceptable to us and an alternative approach should be investigated.

3.1.2 The proposed solution: settlement procedure

First version: without traders

There is another way of dealing with the problem, which is very much related to the way contracts are treated in bilateral markets. Let us consider a simple case where we assume that the real time happens immediately after the reference market, so we ignore at this moment the effects associated with changes in production or demand that may happen after the closure of the reference market —this is considered afterwards in section 3.3—. In this situation, let us assume a certain generator and a certain demand that have engaged into a long term contract covering the whole capacity of the generator. Let us assume also that the generator has sold again his complete capacity through the capacity auction. And, finally, let us assume that at a certain moment the price in the reference market is above the strike price and that the generator is producing at his maximum output. We would like to have this group with no penalty, neither implicit nor explicit, associated to the reliability mechanism.

At the time when the prices were high, the generator —which we consider here as a program responsible party— would have declared that he is producing his maximum output and would have declared that he is selling it to the consumer through a bilateral contract, but he would not be participating in the reference market. Similarly, the consumer would have declared his demand and the contract with the generator, and both of them would have been considered balanced. The option would generate an obligation to pay for the generator, for the amount of money resulting from the difference between the spot price and the strike price —the shaded area in Fig. 2—, which implies a risk associated to the reference price for the generator that we would like to eliminate. But, at the same time, a right would be created for the consumer to receive the same amount of money, as an option holder. Thus we can use a settlement procedure to charge the generator only for his net position at the reference market —only for the energy he is selling into the spot market, but not for the energy he sold through the long-term contract—, and to pay the demand only for his net position.

Then, considering that the first objective of the design is not to punish the parties that decide to engage into long term contracts, we should allow any generator/consumer pair to net out their positions, so that the implicit penalty that the generator has to pay when the price is above the strike price can be compensated with the income that the consumer is entitled to receive. Accordingly, both of them will be isolated from the volatility of the spot price unless they deviate from their contracted position.

Considering this, the process would be as follows:

- Immediately after the reference market closes, each program responsible party submits a balanced energy schedule (equivalent to the ones that are submitted nowadays before the balancing mechanism takes place, and with the same requirements of internal and external consistency [Beune & Nobel 01]), where energy production and exchanges with other parties are declared.

- When the price at the reference market exceeds the strike price,
  - producer i will have to pay the implicit penalty —the difference between the spot price ρ and the strike price s— for the total amount of capacity committed in the auction q_i minus the energy sold to other parties outside the spot market (i.e., through long term contracts) $g_{i,sold}$
  - consumer i will receive a compensation —the difference between the spot price ρ and the strike price s— related with his actual consumption d_i (as declared at the energy program) minus the energy bought in the long term $g_{i,bought}$
  - Or, more generally, the compensation that player i —who comprises both generation and demand activities— has to pay as an implicit penalty will be

    $$(\rho - s)\cdot\left(q_i - d_i - g_{i,sold} + g_{i,bought}\right)$$

- Also, when the price at the reference market is above the strike price, the production declared in the energy program is compared with the capacity committed in the capacity auction in order to determine the explicit penalty for the generators, if applicable.

  $$pen\cdot\left(q_i - g_i\right)$$

  where g_i is the production declared in the energy program[3], and the explicit penalty is only applicable if $q_i > g_i$.

Second version: with traders

However, there is a second objective of the design that must also be considered: traders and parties that are not clearly a generator or a demand should be allowed to actively take part in this market with no difficulty. If the previous scheme is adopted, some problems may arise in this regard. For instance, a problem may appear in a case where a certain generator sells his energy to a trader through an OTC contract, which in turn sells it into the spot market. Since the generator has sold his capacity in the long term, he would not be liable for the implicit penalty, according to the settlement process we have just defined, and since the trader does not hold any reliability option he would not be liable either, therefore no one would be responsible to compensate the consumers for the high prices.

This means that the previous settlement scheme is not totally suitable when intermediate traders are considered and that some refinements are required. One possible way of

[3] Since in this section we are assuming that nothing happens after the reference market closes, the production declared in the energy program is also the actual power output of the generator.

handling this problem consists in asking the parties to declare two different numbers in their energy programs: one is for the energy produced or consumed and transacted with other parties, as usual, and the other one is for the obligations derived from the reliability options. More concretely, this second set of numbers is used to determine who will be responsible for paying the implicit penalty.

It is not possible to use just one program for both purposes, since the total production capacity of a certain unit may be higher than the capacity he commits in the reliability options. Thus, when the generator is selling for instance 100 MW into a contract but is keeping another 100 MW to sell at the spot market, and the unit holds 150 MW of capacity options, the settlement mechanism needs him to state somewhere if the implicit penalty derived from the options is associated to the energy he sold trough the contracts or to the energy he uses to sell into the spot.

In this case the generator would, for instance, declare the following. There will be two figures for his production (200 MW and 150 MW), meaning that he is producing 200 MW and only 150 MW of them are subject to the obligations derived from the reliability options, two figures for his contract (100 MW and 100 MW), meaning that he has sold 100 MW and all of them are associated with an obligation to pay the implicit penalty, which are being passed-through to the other party in the contract, and finally two figures for his exchange with the reference market (100 MW and 0 MW), since he has sold 100 MW in this market and no reliability obligations can be linked to that sale. Therefore, he will be only responsible for 50 MW of implicit penalty; the other 100 MW will be in charge of the counterpart in the contract.

Being more general, we can consider that the implicit penalty is just a financial product that is essentially something that can be traded freely, so the generator could nominate any other party to be responsible for that implicit penalty, even some third party that is not buying or selling energy to him.

On the other hand, the explicit penalty is associated directly to the output of the unit, so it is just the energy program which is used to determine if a certain party has to pay an explicit penalty or not. This payment is related to a physical delivery obligation, so it should not be tradable, and just the actual energy dispatch —and not the contracts— has to be considered to determine if the requirement is fulfilled or not. —Note that we are now ignoring for the time being that the production may change between the reference market and the real time, so we are now assuming that the energy schedule provided by the parties is equal to their actual production (this question is discussed later in section 3.3)—.

Therefore, the final procedure would be as follows.

- Immediately after the reference market happens, each program responsible party submits a balanced energy schedule (equivalent to the ones that are submitted nowadays before the balancing mechanism takes place, and with the same requirements of internal and external consistency [Beune & Nobel 01]), where energy production and exchanges with other parties are declared.

- This program also includes data for capacity, where each party declares his obligations or rights associated to the payment of the implicit penalty. For generators, this includes their commitment resulting from the capacity auction and the obligations or rights sold or bought to other parties. For demands, this includes the rights derived from their actual consumption and the corresponding trading of obligations or rights. These schedules must comply with the external consistency requirement —which states that if party A is selling to party B, then party B is buying the same amount from party A—, but not with internal consistency —capacity programs do not have to be balanced—.
- When the price at the reference market exceeds the strike price, the obligations (to pay) and the rights (to receive a compensation) derived from the implicit penalty for each party are calculated from the previous capacity program.

$$(\rho - s)\cdot\left(q_i - d_i - \sum_j R_{i,j}\right)$$

where ρ is the spot price and s is the strike price, and q_i represents the amount of reliability options sold by the program responsible party i, d_i represents the actual demand of party i and $R_{i,j}$ is the net amount of rights that party i has bought from party j[4].

- Also, when the price at the reference market exceeds the strike price, the production declared in the energy program is compared to the capacity committed in the capacity auction in order to determine the explicit penalty for the generators, if applicable.

$$pen\cdot(q_i - g_i)$$

Where g_i is the production declared in the energy program, and the explicit penalty is only applicable if $q_i > g_i$.

Thus, a generator and a consumer who engage into a long term contract may decide to declare a program for capacity similar to their energy program and, for instance, declare that it will be the consumer the one who will be responsible for all of the obligations and rights derived from that amount of power, for both of them —the generator is passing-

[4] In fact $R_{i,j}$ is the sum of the rights bought, plus the obligations sold, minus the rights sold, minus the obligations bought by party i to party j.

through his reliability obligations to the consumer—. Therefore, when the price raises, the generator will not have to pay the implicit penalty since $q_i - R_{i,j} = 0$. The consumer will in theory have to pay that implicit penalty, but at the same time he will be receiving the income he is entitled as an option holder, so his final payment will be zero. This is the effect that was achieved with the first settlement design presented in this section, and it can be still achieved under this second design.

But this second solution is more flexible. For instance, if the generator sells all of his capacity through an OTC market to an anonymous trader, the unit may typically decide to sell to the trader at the same time the obligation to pay the implicit penalty, in order to avoid any exposure to the prices in the reference market. The combined result of both sales will be a price equal to the expectations of the two parties on the evolution of the prices of the reference market, but excluding the prices above the strike price. It will be lower than an energy-only contract, but it will reflect the typical income that the generator would have received from the spot market, having his price capped to the strike price. If the trader has no other trade and sells this energy into the reference market, when the prices at this market result to be high the compensation that the generator would have to pay will be calculated as $q_i - R_{i,j}$, being q_i the capacity committed in reliability options and $R_{i,j}$ the capacity sold to the trader. Assuming that in this example both are equal to his maximum output, then the generator would pay nothing. The obligation to pay the implicit penalty for the trader would be calculated as $R_{i,j}$, so he will be paying for this compensation instead of the generator. Since he is also receiving the spot price from his sales, this is just equivalent to a cap on the price he receives.

On the other hand, the trader may resell the energy to some consumer through a long term contract. In this case the consumer, at the same time, may want to include in the deal his right to receive the compensation derived from the option, so the price in this second contract will be again somewhat lower than the energy-only price. Thus, the trader has an opportunity to be balanced in capacity and to be hedged against the risks associated to the implicit penalty. If he does so, for the trader we would have $\sum_j R_{i,j} = 0$, so his payments associated to the implicit penalty would be zero. And for the consumer, the obligations derived from $R_{i,j}$ will be compensated with the rights derived from d_i, so all of the parties will be in balance in this case.

However, any other solution, including the possibility that some parties may want to take the risks associated to the options and take a net position in the capacity program, can be handled by the mechanism. For instance, a generator may keep the reliability obligation and sell only the energy. These are financial positions which should not cause any problem. The financial part of the option is a derivatives contract that can be traded freely in as many instances as the parties want, with apparently no difficulties associated to it.

The market seems to provide elements to everyone to decide how much does he want to hedge —or not— against this risk.

This second approach to settlements makes it possible to have a market with a large amount of intermediate traders with no interferences related to the reliability options, which become completely compatible with this market structure. A second product potentially subject to trading appears: the financial part of the option. Normally this product will be traded together with energy, probably through some combined contracts, but all the possibilities are open so parties can find in the market which are the kind of deals where they feel more comfortable with.

It is important to note that the settlement procedure is formulated in terms of program responsible parties, and it is completely symmetrical for generators and consumers. It seems that results are the same regardless of whether it is a certain generator or a trader who is selling the energy at the market. Since the procedure is completely transparent in regards of who is the one who is actually selling or buying, we do not envision any means of manipulating the market by creating intermediate traders or through multiple instances of selling and buying the energy. In this sense, it seems that the procedure is robust and is not easily prone to gaming due to the trading activity[5].

3.1.3 A third approach: making the options physical

Finally, there is a third possibility that was raised during the discussions held with DTe during the development of the project[6], which we have not explored in depth since there are some implementation problems that make us prefer the settlements solution.

Strictly speaking, a call option gives one the right to buy the subjacent product at a certain predetermined price, which is the strike price. In previous sections we have been using the *derivatives* version of the option, where the buyer of the option acquires the product at the spot price and receives a compensation for the extra cost, but we could also explore the alternative of doing it in a physical way. Under this version, the buyer of the option physically asks the seller to produce and pays him the strike price.

This would require to establish some "options administrator" —probably the same party that in the latter alternative would be responsible for the settlements— who will require

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[5] Regarding gaming potential, more concerns may appear in relation to the possibility of selling the energy in different markets. For instances, a certain generator may sell his energy at the reference market and then declare he is unavailable at the balancing market. These temporal effects have been ignored in this section and will be treated below in section 3.3.

[6] This alternative was raised during the discussions with DTe, after the interaction with a similar project funded by APX.

the option-holder generators to produce whenever he thinks it is necessary. Accordingly, consumers would go to the reference market to buy their energy knowing that they can have it at the strike price if they want and, thus, they would place a demand bid stating that they are willing to buy the energy but they do not want to pay more than the strike price —otherwise they will wait and call their option—. If this strike price is exceeded at the reference market, consumers will not buy at that market, and the options administrator would ask the committed generators to produce instead. These units will be paid just the strike price.

We see some problems related to this scheme. The first one is that it is not very clear which of the option-holder generators should be called to produce when some of them is required. Normally there will be more reliability-options capacity available than the required amount, and it may be difficult to establish some merit order between these units. It looks likely that the production decisions at this emergency stage may not be completely efficient.

The second problem we envision is related to the trading process of the generators. If they know that they may be required to produce after the reference market takes place, they will increasing their risk if they participate in the auction at the reference market or in any previous market. If they are already sold and the options administrator call them to produce, they will be in trouble. Thus, they should wait until the reference market is finished, and the decision of the options administrator is taken, in order to trade their energy at no risk. But if there is a large number of generators holding options, then it would be difficult to trade at the reference market. And this seems to be an inefficiency in the performance of the market.

In any case it is likely that some of these problems might be overcome by wise changes to the rules. However, we have not explored this topic in very much depth. We have opted for the settlements way of thinking, which is the implementation scheme that we have further developed and which we are proposing, because we think that more elegant solutions may be obtained from it[7] but, indeed, we do not discard completely the other approach, and perhaps a more thorough exploration of it may eventually lead also to some interesting solution.

[7] Intuitively, it seems that in theory both solutions would be equivalent, but the physical approach that we are now discussing would require more arbitrage abilities from the parties, while the settlements scheme might be easier for them. Using a not very strict analogy with the congestion management problem, the physical procedure shares some of the problems of the explicit auctions while the settlements approach is more similar to a market splitting.

3.2 Selecting the reference market

One central question related to the previous discussion is to determine which is the price that we shall consider as the reference price; i.e., which will be the price that triggers the reliability options mechanism. The options will become binding when that price exceeds the strike value and they will have no consequences —in the short term— for lower prices. In order to define the product completely, it is necessary to identify which is the spot price that will be considered as a reference. Two are the main candidates: the prices in the day-ahead market in the APX and the prices in the balancing mechanism.

3.2.1 Long-term markets

The prices in longer term markets do not seem to be useful solutions. Since the options are intended to identify the moments when the system is near rationing, in order to provide short term incentives for the generators to be available during the most critical periods, it is important to define the reference market close enough to the short term so that the real conditions in the system that affect supply —changes in generators availability, changes in imports, cooling constraints, etc.— are reflected in the price signal and have an influence in the operation decisions of the option-seller generators. An option referred to the price of, for instance, a six-months-ahead futures market compels the generator to be ready to sell in that six-months in advance market, but provides no additional incentive for him to react if prices in shorter term markets change with respect to the reference one.

The reference market should be rather close to real time. For shorter term periods, the reserves mechanisms operated by the System Operator start acting. The reference price represents somehow a frontier between the time scope where the generator who has sold an option has incentives to take operational decisions taking reliability into account —i.e., the period where reliability decisions are guided by the guarantee of supply mechanism— and the time scope where those incentives are provided by some other means, typically in the form of ancillary services (reserves) managed directly by the System Operator. It is an advantage to have a reference price which is close to real time, since that makes the generators optimize their decisions knowing that they have to be ready to produce when there is a shortage. Under this scheme, decisions such as when to undertake programmed maintenance, or how much of it should be done in order to reduce forced outages, or how to contract gas supplies will be taken considering their impact on reliability, and therefore reliability is expected to be enhanced.

3.2.2 Balancing mechanism

According to what has just been said, it seems that we should try to move the reference price as close to the real time as possible. Thus, defining the balancing mechanism as the reference market for the reliability options will be an improvement with respect to the day-ahead market run by APX.

However, there is a problem with having the balancing mechanism acting as the reference market and having the price resulting from it triggering the reliability options. There are some generators that cannot participate in the balancing mechanism because of technical reasons. Selling an option that is referenced to the balancing market means that the option-selling unit should be ready to sell his energy at the balancing mechanism if the price at this market is high; otherwise he would be bearing a penalty. Unfortunately, the balancing mechanism is run quite close to real time and a number of generators — specially base-load units— are not flexible enough to produce if required by the balancing market unless they have taken some operational decisions beforehand —typically, starting the unit up—. And even if they do start up the generator ahead of time, ramping constraints may also limit to a great extent their performance in this balancing mechanism.

Therefore, for a number of base-load generators, it may be difficult to participate in the balancing market and, in the most optimistic case, it will imply for them the need to incur in a number of costs that may not be remunerated if they finally are not required to produce at the balancing mechanism. This in general will not be efficient for the system as a whole. The result of this is either to exclude the base-load units from the guarantee of supply mechanism or to have an inefficient over-dimensioned spinning reserve. For instance, this may lead to a situation where in a valley hour during the spring, where demand is very low, all of the capacity that is not producing in that hour but may be required in a future peak hour will be part of the spinning reserve. This is inefficient and expensive, and may be a relevant objection to the method.

A slow generator will be burdened with a sizeable risk if he is required to be ready to produce when the balancing price rises up, so they should not be forced to participate in this market. Setting the reference for the reliability options at the balancing mechanism may preclude the participation of some kind of generators in the capacity market — typically, coal units—. Since coal seems to be a plausible alternative for system expansion, depending on gas prices, the regulatory scheme should not systematically discriminate against them.

At the same time, it seems that there is currently a problem in the Dutch market related to a lack of supply at the balancing market. Setting the reference market at the balancing mechanism would enhance liquidity at this market, while setting the reference before would not help to correct the problem —although it would neither worsen it—. If the reference is set before the balancing, although there may be an scarcity situation at the balancing market and an option-seller generator may have some spare capacity, he would have no obligation to participate in the balancing market. Only the present incentives based on the balancing price would apply. Setting the reference price as the price resulting from the balancing market would create an additional incentive to participate in this balancing mechanism. However, we recommend not to try to solve this problem of liquidity in the short term through the reliability options mechanism. This would imply some other difficulties —discriminating against the slow generators, as we have just discussed— that should not be accepted. Instead, we think that the Dutch market should try to handle the liquidity problem at the balancing mechanism by other means, typically with measures that are just related with the short term rules. For instance, a fixed payment for the balancing market may be established: a payment for generators to be ready to sell at the balancing mechanism. However, these changes to the rules exceed the scope of our analysis and we have not considered them.

3.2.3 Six-hours ahead

Thus, it seems that the reference horizon for the reliability options should be established far enough from real time to leave room for all generators to react and be ready to produce if their bids are accepted at the reference market. But, provided this condition is satisfied, the reference market should be placed as close to real time as possible, in order to provide better incentives for plant operation. Considering the technical characteristics of the Dutch generators, probably a six hours horizon would be enough to achieve these results. We could organize a new six-hours-ahead market for this purpose. Since nowadays this market does not exist, it may probably result to be very illiquid, and it may primarily used just for reliability-related bids; i.e., generators would tend to place bids at prices near the strike price for the part of their committed capacity that they have not sold in previous markets, to be sure that they will be generating if the prices are high, but may have no interest in selling energy at "normal" prices here, and only demands that could not find a better deal before would attend this market.

The critical issue with this approach is the question of exporting. Assume that we have a certain generator which has sold a number of reliability options and which estimates that his output would not be required in the Dutch market. Then, he may be willing to export his capacity and sell it to some other market. However, when doing so he will be bearing some risk, since if he sells his output abroad and finally there is a problem at The Netherlands he will be required to produce for the Dutch consumers. Since he has already sold his energy, he would have to pay the implicit penalty. Therefore, it seems that exporting is a rather risky business for a generator that has been awarded some reliability options or, in other words, that reliability options may be a problem for exporters.

This would not be risky if the exporting decision could be taken after the reference market is run. In this case, the generator would check if he is required or not to produce at the Dutch market and, if not, he would try to sell his power at some other market. If the reference market is set six hours ahead of real time, there is little room to try to find some interesting counterparts to trade with afterwards. In the particular case of The Netherlands, the most likely market to export the energy in the short term might be the German EEX, which happens to close after the APX day-ahead market. So, if the reference is set at the day-ahead Market run by APX, then there is still some room for exports selling at the EEX, and that would not imply any risk.

If a certain generator who has already sold options wants to sign an export contract on the long run, it would certainly imply some risk for him, since he may be asked to pay the implicit penalty if the Dutch market is near rationing, but this is a natural consequence of the reliability options mechanism that should not be eliminated: the generator should not sell his capacity twice and if he does so, he might be penalized. Instead, the generators holding some reliability options should try to design their exporting contracts conditioned to the prices on the Dutch market. For instance, it may be stated that the contract will not apply if the prices in the Dutch market are high.

On the other hand, setting the reference market at the APX day-ahead market, releases the option-holder generators from their capacity obligations if no trouble at the Dutch system has been detected once the day-ahead market closes, allowing them to export their output afterwards to the EEX with no risk. This is an ad-hoc solution that minimizes the interference of the reliability options in the process of capturing the potential benefits associated with exports, which exploits the current temporal organization of the different markets. It may have to be rearranged if the horizons of the organized exchanges are modified —or, reversely, markets would tend to keep this structure in order to exploit this advantage— but, in any case, it seems to be a reasonable solution for the market as it is now.

3.2.4 Day-ahead market

Thus, it seems that the day-ahead horizon is the most suitable solution for the reference market of the reliability options mechanism. All units are more or less technically capable of producing if notified one day ahead, and export trading is made easier when the reference market happens before the EEX gate closure. Under this solution, the generators are forced to plan their operation decisions (maintenance, gas contracts management, etc.) in order to be ready to produce all of their option-committed capacity whenever a raise in the price of the day-ahead market triggers the reliability mechanism. And, moreover, they have an incentive to negotiate their power no later than in the day-ahead market. If a certain generator has some capacity that he sold trough a reliability option but that he has not sold in the long-term markets, he should place a bid at the APX auction. If he does not and the prices at the APX rises above the strike price, then he would have to pay the difference between the spot price and the strike price, plus the explicit penalty for not producing.

Accordingly, the generators who have sold these reliability options would have a strong incentive to be producing whenever the price in APX is high. Thus, they would tend to place bids at this market for all the non-used part of the capacity they have committed through the options, with a price at most slightly inferior to the strike price of the option, in order to be sure that they would be part of the APX schedule if the prices are high. The generators that usually do not trade in the APX will also have to place bids in this auction, typically at a high price almost equal to the strike price, that most of the time will not be accepted by the auction, because they are too expensive. Thus, the volume of bids submitted in this market would be increased, with an apparent increase in liquidity, although that will not mean such an important improvement of liquidity since a large part of them would be only used when the system approaches emergency conditions.

Since any option-holder generator would try to place a bid at a price lower or equal to the strike price in order to be sure that he would not be penalized if he is available to produce, high prices at the APX market would only occur when there are no enough option-seller generators available.

This somehow represents a change in the role of the APX day-ahead market. For an option-holder generator, this is the last market where he can trade his energy without being penalized, at least during the periods where the prices are above the strike price. Therefore, it looks likely that during these periods the APX would tend to concentrate part of the trading that nowadays is done in shorter-term markets. For the generators who sold reliability options, the markets that happen after the APX would only be used to solve for outages or other circumstances that arise after the day-ahead market has closed. This represents a change with respect to the present functioning of the system, giving a more central role to the APX market, but we see no way of avoiding this feature, since we need to define a reference market where the short-term obligations are enforced. This is necessary to implement the reliability options scheme, but we think that it should not be a major problem, since it only applies to the periods when the system is in emergency conditions, so its real effect is just to concentrate trade in the day-ahead market when the system is short of capacity —and it is probably good to know in advance if a critical situation is going to happen or not— but it does not limit trading at all if the prices are lower than the strike price.

On the other hand, some concerns may arise regarding the fact that the day-ahead market run by APX might not be very liquid and it may be prone to manipulation. This does not seem to be a specific problem for the reliability options mechanism —although it is a concern indeed for the whole performance of the market—, since generators are committed just to produce whenever the spot price is above the strike price. There is a reasonable strategy for them consisting of bidding at a price slightly less than the strike price, and that strategy protects them of being penalized if they are ready to operate. Any generator can do so regardless of the evolution of the prices and the bids of the rest of the competitors, so they should not be very much affected by market manipulation. The most critical factor for an option-seller generator is his availability during the critical periods. Of course, if market manipulation makes it more difficult to predict when the price spikes would happen, decisions regarding scheduled maintenance, for instance, may be complicated, but this would be also the case if there were no reliability options.

3.3 Interaction with shorter-term markets: the balancing mechanism

The previous reasoning in section 3.1 did not consider the existence of the balancing market and the real-time functioning of the generators and consumers. This implies that it is possible to have a real-time energy production that is different than the energy scheduled at the balanced program submitted after the day-ahead market closes. It is important to consider how the interaction between these different time frames can have an influence in the performance of the reliability mechanism.

3.3.1 Proposed mechanism

In order to avoid any potential gaming of the rules, when using the possibility to negotiate in different time frames, we propose the following modifications to the settlement procedure described in section 3.1:

- Immediately after the APX day-ahead market closes, each program responsible party submits
  - a balanced energy schedule, where energy production and interchanges with other parties are declared, and
  - a capacity schedule, where each party declares his obligations or rights associated to the payment of the implicit penalty. For generators, this includes their commitment resulting from the capacity auction and the obligations or rights sold or bought to other parties. For demands, this includes the rights derived from their actual consumption and the corresponding trading of obligations or rights.
- When the price at the reference market exceeds the strike price, the obligations (to pay) and the rights (to receive a compensation) derived from the implicit penalty for each party
  - are initially calculated from the previous capacity program.

    $$(\rho - s)\cdot\left(q_i - d_i - \sum_j R_{i,j}\right)$$

    Where ρ is the spot price and s is the strike price, and q_i represents the amount of reliability options sold by the program responsible party i, d_i represents the demand declared by party i in the program submitted after the day-ahead market, and $R_{i,j}$ is the net amount of rights that party i has bought from party j.
  - Additionally, if the real-time consumption of a certain demand is less than the energy d_i declared in this next-to-day-ahead program, the capacity rights

awarded to the firm are reduced according to the difference. Total obligations would be

$$(\rho - s)\cdot\left(q_i - d_i^{scheduled} - \sum_j R_{i,j}\right) + (\rho - s)\cdot\left(d_i^{scheduled} - d_i^{real\,time}\right)$$

$$d_i^{scheduled} > d_i^{real\,time}$$

Or, equivalently

$$(\rho - s)\cdot\left(q_i - \min\left\{d_i^{scheduled}, d_i^{real\,time}\right\} - \sum_j R_{i,j}\right)$$

- Also, when the price at the day-ahead market exceeds the strike price, an explicit penalty for the generators is determined, if applicable.

  $$pen\cdot(q_i - g_i)$$

  $$g_i = \min\left\{g_i^{scheduled}, g_i^{real\,time}\right\}$$

  where g_i is the minimum between the production declared in the energy program and the real-time production, and the explicit penalty is only computed if $q_i > g_i$.
- Additionally, when the price at the day-ahead market does not exceed the strike price but the price for buying power from the balancing mechanism ρ_b is higher than the strike price, then every party buying from the balancing mechanism is also charged the explicit penalty pen. This can be considered analogous to the existing incentives to penalize intentioned unbalances.
- Finally, we are assuming that the present incentives to avoid real-time unbalances are high enough to ensure that it is better for a generator to declare in advance that he cannot produce —either at the day-ahead market or at the balancing mechanism— than paying for these real-time deviation charges, even if the first alternative implied paying an explicit penalty. Otherwise, these real-time incentives should be enlarged.

We shall now examine how these elements help to cope with the interaction between the different markets.

3.3.2 Too high declared generation

The first case we shall consider here is a generator that, when preparing the balanced program that he must submit after the day-ahead market, decides to declare an energy generation that is higher than the energy he can produce. He will wait until some moment closer to real time to declare he is unavailable. We know that if an option-holder generator declares that he is unable to produce at the day-ahead market he will have to bear a penalty. Thus, he would like to say he is ready to generate at the APX market and try to forego the explicit penalty, and only afterwards he will declare that he cannot produce — he may say, for instance, that he has just had a forced outage—. By doing so, he would be paying a high price for imbalances, but if he succeeds in avoiding the explicit penalty this may be a profitable strategy in most occasions.

However, the explicit penalty that is due in the reliability options scheme is computed using the smallest of these two figures: the production declared in the energy program submitted after the day-ahead market, and the real-time generation. This unit will be finally producing less than expected, the procedure will detect that, and the generator will be charged the explicit penalty, regardless of his eluding strategy of overstating his production in the initial program. Moreover, the firm has an incentive not to follow this strategy and to declare early that the unit is not ready to produce since the prices at the spot market tend to be lower than the prices at the balancing mechanism or other instances closes to real time and, thus, the payments —implicit penalty— that result from the day-ahead market are also lower than the cost of buying the energy afterwards.

But such a bidding strategy may have more dramatic effects. It may happen that the generator, by overbidding in the day-ahead market, could make the spot prices fall and lead the reliability procedure not to trigger. If, during the APX auction, there is some amount of capacity declared as available to produce —and waiting, for instance, to the balancing market to disclose they are unable— it may happen that the price at the APX remains relatively low and no problem is detected. All of the rationing signals are postponed and remain hidden during the day-ahead period.

The proposed mechanism would still detect this. If the generator is unavailable but decides to sell energy at the spot market —or before—, he will finally have to declare an unbalance at the balancing mechanism. Therefore, he will have to pay the price resulting from the balancing for his energy, which will be normally higher than the day-ahead price, so the generator would be indirectly paying the implicit penalty. If there is really a scarcity problem at the system, then the price at the balancing market would be higher than the strike price and this balancing price will be incremented in the value of the explicit penalty. Thus, the penalties that the unit is perceiving are at least equal to the ones that he would have paid if he had declared at the day-ahead market that he could not produce. If the price in the balancing market is low —below the strike price—, this means that the system is not near rationing and no explicit penalty is charged in this procedure. In general, no explicit penalty would have been charged either if he had not sold any energy at the day-ahead market, since the spot price would have also been below the strike price.

Finally, related with this latter situation, another factor that should be considered here are the incentives that option-holder firms have, when they are partially unavailable, to negotiate with other parties in order to try to keep prices at the spot market low and avoid the reliability options mechanism triggering. The generators that had sold some options but cannot produce —and they expect the prices to be high— would try to buy outside the reference market the energy the committed into options, and then resell it at that reference market at a low price —in fact, at a price only slightly lower than the strike price—. By doing so, they will be paying something equivalent to the implicit penalty, since they may be buying the energy at a high strike price and reselling it at a lower strike price, buy they may be not paying the explicit penalty, since the reliability options mechanism will not be triggering. However, the fact that they may be charged with a explicit penalty is know by all firms in the market, so it may have an influence on the price that other parties ask them when buying the energy, and probably the explicit penalty is included, at least partially, in the prices they pay.

In any case, strategies like these are not easy to implement for a generator, since most of the times option holders can not know in advance whether these kind of individual actions will be enough to push the prices down and avoid the triggering of the reliability options mechanism. If they not succeed in keeping the prices below the strike price, they may be losing money when buying in the previous markets. Nevertheless, this kind of movements tends to reduce the times in which the spot market shows prices above the strike price.

3.3.3 Too low declared generation

Another relevant case in this study would consist in a certain generator that decided not to participate in the APX spot market, even if he had not sold his energy in any previous market. Accordingly, he would declare no production at the energy program that he presents after the day-ahead market. Then, the generator may detect that the prices at the spot market are high, so he is in trouble considering his reliability options commitments, and thus the unit would try to increase his production by selling the energy in the markets that are closer to real time.

The reliability options mechanism would charge this generator an implicit penalty for the production declared at the energy program, and an explicit penalty for the minimum between the programmed output and real-time production. He will have to bear an explicit penalty because he did not produce at the reference market when the system was near rationing and the prices were high, just as if he had not produced. The generators are required to sell their energy before the day-ahead market in order to comply with their reliability requirements.

However, for this unit, once he has been penalized, he still has the opportunity to receive the price for selling at the balancing market. Accordingly, all of the incentives to participate at the balancing market remain operating, even if the decided not to participate in the previous markets. The unit would had been better off if he had produced at the day-ahead market, as required by the mechanism, but there are still incentives for him to operate efficiently once he detects that he should be producing, so he will try to generate at the balancing mechanism.

3.3.4 Too high declared demand

A consumer may want to declare a high demand in the program that he submits immediately after the day-ahead market closes, since he obtains rights for every megawatt he consumes. If he reduces, latter on, his consumption, he may keep the rights resulting from the energy program and obtain some money from it. This is why the proposed mechanism only awards rights to the demand corresponding to the minimum value of these two: the scheduled power and the real-time consumption. If the demand is reduced after the energy program is submitted, then the amount of rights assigned to that consumer would be reduced. So there are no incentives to try to inflate that value in order to obtain more income.

Also, the consumer may try to declare a high demand so a generator from the same firm may declare a high production, even if he is unavailable. Then, the demand would go to the balancing market and would declare an unbalance that implies a reduction in its consumption, and the generator would present a bid showing that he is able to solve the problem, selling some reduction in his production. This could allow the generator to avoid the penalties associated to the reliability option although being unavailable.

Under the proposed scheme, the generator would be charged for the minimum between his real time production and the scheduled one, so he would be penalized even if the reduction resulted from a requirement from the balancing market. In this way we try to avoid any gaming of the system through the balancing market. This is why the proposed mechanism does not consider the case of high prices at the day-ahead market and, then, excess generation at the balancing market. We think that this will not be a frequent case, and if it happens, then the operation reserves should be the ones that must reduce their output in order to compensate. Otherwise, gaming opportunities may arise.

3.3.5 Too low declared demand

Finally, the demand could try not to declare his real consumption at the day-ahead market in order to keep the prices low and try not to trigger the reliability mechanism. This is equivalent to the case where the generator declared more output than really available. Then, the consumer would have to attend to the balancing market where the price would be high —if neither the price at the day-ahead market nor the price at the balancing are high, then the system is not in trouble, assuming that real-time deviations are severely penalized—. He would be a buyer at that market and, attending to the rules we have established, he would also have to pay the explicit penalty for his additional consumption. So the penalty that the generator was allowed to avoid by this coordinated strategy is finally charged to the consumer, and there is no way of gaming the system by doing so.

The existing penalties related with real-time deviations should be restudied considering this issue, in order to determine if they are high enough to discourage this kind of gaming: a generator that declares he is available in order to avoid the explicit penalty, even if he has to pay for the real-time deviation punishment. Probably this real-time deviations should be penalized in a stronger way when the reliability options mechanism is in operation.

3.3.6 Conclusion

We have devised a procedure to deal with the different time frames within the energy auction. We have exhaustively analyzed the potential for gaming in this scheme and we found no way of significantly doing so. Perhaps some other problem may arise, but we have tried to study all of the possibilities and we think that the system is robust and provides reasonable incentives for trading under this scheme. In our view, the mechanism leads to a sensible solution and can be implemented in the Dutch market.

3.4 Imports and exports

3.4.1 Exporting parties

Another very relevant issue is the treatment of imports and exports. Let us start with exporters. Typically, exporters can be represented by a generator, that may or may not hold any reliability options, and an external demand who is not holding options. Or by any combination of traders buying energy and capacity obligations/rights to these parties. The only difference with any other transaction is that the external demand is not measured explicitly in real time; instead, the exporting program declared to the TSO is used, but everything else remains equivalent. But we will accept here that both are completely equivalent, since the Dutch TSO is in charge of enforcing those exporting programs.

Thus, if we apply the settlement procedure that was described in the previous sections, then we would see that when the energy for the export comes from a generator who does not hold any option, then no obligations appear related to this trade. When the energy comes from an option-seller generator then, if the prices in the Dutch market happen to be higher than the strike price, someone has to pay the difference between the strike price and the spot price. In the simplest case, when it is just the generator who is exporting, then all contracts with other parties in the system are cero $R_{i,j} = 0$, it is the generator who has to pay for this implicit penalty: he holds some options that are not compensated by any demand. Exports do not have reliability rights, so they do not compute as a demand, and finally the generator has to pay an implicit penalty for all the capacity he committed in the reliability auction.

$$(\rho - s)\cdot\left(q_i - d_i - \sum_j R_{i,j}\right) \quad \Rightarrow \quad (\rho - s)\cdot q_i$$

In a more complex case, with a trader buying the energy from the generator and then exporting it, we can assume that the generator would sell the capacity obligation together with the energy. Thus, for the generator the commitment will be compensated with the obligations that are assigned to the other party —the trader—. For the trader, the obligations accepted cannot be compensated with the sales to the foreign demand, so he ends up paying the implicit penalty.

Generator: $(\rho - s)\cdot\left(q_i - d_i - \sum_j R_{i,j}\right) \quad \Rightarrow \quad (\rho - s)\cdot\left(q_i - R_{i,j}\right) = 0$

Trader: $(\rho - s)\cdot\left(q_i - d_i - \sum_j R_{i,j}\right) \quad \Rightarrow \quad (\rho - s)\cdot R_{i,j}$

This effect also has the ability to act as a protection for Dutch consumers. Since they are hedged against the high prices at the day-ahead market, they can always bid a very high price and buy the energy in this market. Any potential consumer from another country that participates in the day-ahead market and tries to buy some energy when the system is short and the options are binding will have to pay the spot prices, and he will find that the national consumers can easily outbid him since they are protected against the high prices.

From the point of view of a trader willing to export, this means that during the scarcity periods the prices in the Dutch market will tend to be higher than the prices in other countries —since Dutch consumers can bid almost any price—, so it will be more efficient for the trader to sell his generation on the Dutch market and try to buy some energy in the foreign market, where it would be cheaper.

It is true that the exporting generator will not pay the explicit penalty, even if he is exporting when the Dutch system is in need. Somehow, the design that we are proposing implies that producing and exporting is not so bad for the system as being unavailable. Somehow, exports are part of the "natural" demand of the system and generators serving them should not be excessively punished. Under our scheme, they pay for the implicit penalty —the difference between the spot price and the strike price—, but no t for the explicit penalty. However, these units are receiving the marginal price for capacity, which includes a part of the explicit penalty, so one could say that it is still a profitable business to sell reliability options even if the generator plans to be exporting every time the price is high. This seems to be a problem with the proposed scheme.

Nevertheless, this is not an optimal strategy for a generator. The Dutch consumers have the right to raise the price in the day-ahead market and that will make the option-holder exporter pay a very high implicit penalty. It would be more efficient for him to produce at the Dutch market, obtain the income that results from the very high prices, and try to buy the energy to export in some other market.

Considering that this "only-export" strategy will never be followed, we have not developed in much detail any solution to charge the explicit penalty to exporters. We think that the proposed settlement procedure provides a reasonable solution. If one would like to charge this explicit penalty to exporters, some modifications on this procedure would be required in order to track in more detail the capacity obligations and identify which is the generator or trader that is responsible for the export.

However, the regulator may not want to rely completely on this approach to grant that the capacity he has bough through the reliability procedure will be ready to be used by the Dutch consumers and may feel more comfortable by adding an additional condition to the reliability options design, which is somehow a safeguard condition. This condition will state that, whenever the price in the spot market is above the strike price, it is not acceptable for an option-holder generator to use his committed capacity for exporting. In that case, the System Operator can compute, using the balanced energy program that parties have to submit after the day-ahead market, the volume of energy that is actually being produced by generators without reliability options —including the non-committed production of the units that are only partially involved in the options mechanism— and limit the total amount of exports to that volume. This means that some of the exporting programs will be rejected. Afterwards, a specific investigation will be required to determine the allocation of the final exports among the different players or, more precisely, to determine which of the parties willing to export were using not-committed energy —so their trades with other countries will be respected— and which parties were willing to export using reliability-committed energy. When buying their energy, potential exporters should consider that this may happen, in order to estimate the potential impact of this rule on their trades. Somehow, the energy committed in the reliability options is less firm than the rest of the energy, since it is not available for exports when the system is near rationing, so buyers must have this in mind when negotiating for this energy. On the other hand, the idea with the ex-post identification that we are proposing here is to avoid the need to track in an hour-by-hour basis which is the origin of the energy that is being exported; this is feasible, but it implies an additional complexity in the settlement procedure that we have considered that should be avoided, especially considering that, as we had presented above, there are strong economic incentives that make this situation rather unlikely, and normally the Dutch generators will not be willing to export when the system is short of capacity.

3.4.2 Importing parties

Regarding imports, just subtracting the expected amount of imports from the required capacity and not buying reliability options to external generators might be dangerous, since these importers have no special commitment with the Dutch system and may not be available when required. Especially in the case of simultaneous problems in the Dutch and the external systems.

Equivalently, imports can be treated as generators that are similar to the rest of the units in the system. They have to be part of some of the energy programs that are declared after the day-ahead market, and penalties are computed in the same way as for every generator, using the settlement procedure described in section 3.3.1. At real time, their actual consumption is not measured, but their importing program is declared to the TSO. If the external TSOs respect them, this is equivalent for importing generators to a real-time production for local units.

The first question related with imports is how to consider the participation of each external generator in net imports. Or, more precisely, is the reliability options mechanism interested in having the external generators that committed in the options producing, or is the Dutch system just interested in having enough generation flowing through the interconnection?.

Following the analogy with national generators, we should ask them to be actually producing when the prices in the Dutch system are high. However, this would make the option-holder generators the most interested parties in buying the transmission rights to enter the Dutch market, and they would tend to exclude any other party from this trading activity. On the other hand, there is a difference between external generators and national ones: for the external generators there are many of them not holding any reliability options that can provide backup if required —since transmission limits do not allow to use them all at the same time—, while for the national generators all of them are supposed to be operating simultaneously and all of them may be needed by the system to avoid rationing.

Thus, we can think of this as a nodal problem. If the reliability options are just referred to the prices in the Dutch node, then all of the external generators would have to bear the risks associated to the transmission network and to the different prices in the different nodes. For instance, if the price at the German node is low —so a certain generator located in Germany is not interested in producing— but the price at the Dutch node is high, above the strike price, then the German generator holding reliability options would be required to produce, and it would be inefficient. Of course, the generator could have included that extra cost in the premium he wants to receive, but the mechanism is reducing the flexibility of the final solution. Thus, it seems to be a better design from the production point of view to relate the option of each generator to the price in his node.

In practice, this means that the options of a German generator would trigger if the price in the Dutch market minus the price of the transmission rights is higher than the strike price. However, there is a problem with this implementation: generators would have to know in advance if the price of the Dutch day-ahead market is going to be high or not in order to buy the corresponding transmission rights. In fact, an options-holder generator in Germany would be penalized if the prices of the interconnection are low —because no one expected a problem at the APX— and he did not bought them —because he did not either expected high prices in The Netherlands— but finally the Dutch prices happen to be high.

The procedure of explicit bids for buying the right to use the transmission capacity relies heavily on the ability of traders to estimate the future prices at both sides of the interconnection. If the trader is some party that holds a reliability option and that wants to make sure that he will be producing when the prices at the Dutch market rise, there is no bid that he can clearly place in the transmission market that allows him to be always ready to produce at the Dutch day-ahead market but not to pay an excessive rent when the price at that market is low. There is no risk-free strategy for this kind of generators.

There are two potential solutions for this:

- Some kind of joint auctioning of transmission rights and energy —market splitting, for instance—, where the uncertainty is eliminated. The German generator holding options could bid at something similar to the strike price, so he would not be accepted most of the time and he will only be called upon when the system is near a crisis. Unfortunately, this solution does not seem feasible in the short term.
- A simplification consisting in considering just the volume of imported energy.

Under this second scheme, an importing generator would be penalized if the price in the Dutch day-ahead market is high and the volume of imported power is less than the volume of external reliability options bought through that interconnection. This is the criteria that triggers the mechanism for external units. Accordingly, the option-holder generator that is located outside The Netherlands would place a bid at the transmission auction with a low price. This bids ensures him that he will have the right to import into the Dutch market if anyone else is willing to do so and that, if he cannot import, then someone else will be doing so. Thus, the option-holder generator will not be penalized in any case, even in the prices at the Dutch market are very high.

However, this does not cover the case where the committed power is being imported but the interconnection prices are low. In this situation, the generators would be receiving a high price and they will not be paying the implicit penalty. This is why this is a simplified approach.

This solution represents somehow a better treatment for the external generators —located outside The Netherlands— than for the internal ones —located inside the Dutch control area—, since their obligations are lower. In some particular cases the external units will not pay any implicit penalty, and they can be replaced by other units in their system with no explicit penalty associated. This apparent discrimination can be resolved by running a nodal capacity auction —see below—, so the price for external generators will only be determined by them, and it would tend to be lower than the price for internal ones. Thus, the differences in the products are compensated by a difference in the remuneration that the generators receive.

Also, some part of the implicit penalties that were in principle due to the external generators will not be collected, although that money will still have to be reimbursed to local consumers. Therefore, a deficit may appear. The income received from the explicit penalties of all of the generators in the system and from the extra implicit penalties —there is more capacity contracted than peak demand, so if there is a problem there will be several generators paying for the difference between the spot and the strike prices— may be used for this. It seems that the financing problem can be solved by these means, and the mechanism will still collect more income than required[8].

3.4.3 The capacity auction itself

When buying the reliability option from the generators at the capacity auction, both internal and external producers should be considered at the same time, with each of them identified according to his location in the network. No more external capacity than the amount that can be transmitted should be bought.

A market splitting mechanism seems to be the most suitable alternative here. The procedure will be as follows:

- A single area auction is performed.
- If transmission constraints are respected, then the results are correct.
- If not, then some internal generators will replace some external ones and two different prices will appear.

Each generator will be paid the marginal price corresponding to his area, and the obligations derived from the options will also be differentiated according to the area in which the generator is located (see section 3.4.2).

[8] This extra income can be used to reduce the payments that consumers have to do for the fixed part of the reliability option —the premium fee—, or to pay for some other general cost of the system, such as transmission investment, or renewable energy support, etc.

3.4.4 Safeguard conditions

There is another relevant question related to imports, which is to which extent would the TSOs of other countries respect the exporting decisions when their own system is in crisis. If they do not, then these generators will be penalized by the Dutch options mechanism. So it will be difficult for them to participate in the capacity auction. Or more precisely, they will be expensive because there is an additional factor of non firmness related to their TSO.

There is a problem with TSO coordination in Europe. Presently, the European Directive allows the TSO of a certain country to retain for his internal consumption the power produced by the generators in his area if there is a risk of shortage. Thus, even if this generator has sold an option to the Dutch reliability system, his own TSO retains a priority in its dispatch. This means that the energy is not firm and may create problems in case of a simultaneous shortage in both countries.

In principle, The Netherlands should be careful with using that kind of contracts for ensuring its security of supply. Some kind of agreement between European TSOs should be required to make sure that the reliability contract would be respected and that the energy sold is firm; otherwise, that import may not be accepted in the auction. Anyway, transitory measures may be implemented initially while promoting a general agreement on the problem across Europe and accept import as a part of the firm supply of the country. We recommend to put some limits on it, such as setting a maximum amount of firm capacity to be bough abroad, or penalizing its bid prices by a certain factor, in order to give some priority in the auction to the internal energy which is firmer —of course, only while the aforementioned agreements are not in place—.

So, the auction could create obligations for the external generators as described before, but they might be paid only 70% (or any other amount) of the marginal capacity price to reflect these concerns. If there are separate prices for the two areas, this price reduction will not be very effective, since only the bids of the external generators are used to compute the price they receive, and those bids were done already considering the 70% reduction. However, this reduction gives some priority to the national generators compared to the external ones, reflecting that their energy is less firm.

3.5 Setting the strike price

The strike price is one of the first variables that has to be tuned when implementing the reliability options approach. In practice, it represents a regulatory frontier between the "normal functioning" and the "near rationing" parts of the market. It is used in the market design to detect when the system is at an emergency condition —spot prices above the strike— so all of the committed generation is required to be ready to operate.

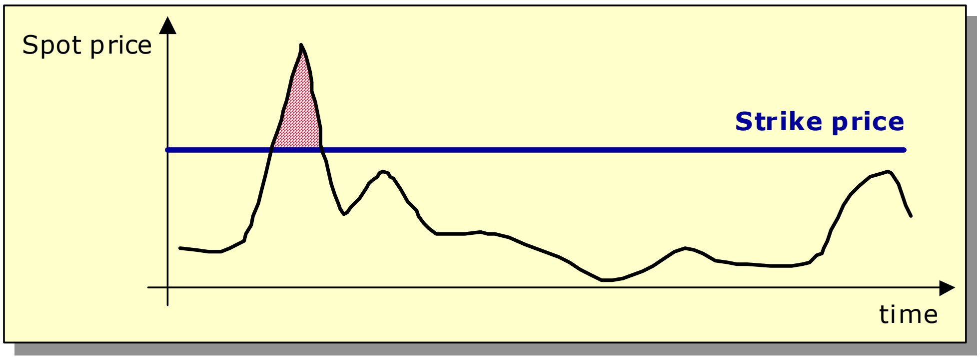

Fig. 3. Strike price

The strike price should be high enough to make sure that no generator producing in normal conditions will be more expensive to operate than the strike price. This way, the options procedure would not interfere with the energy market unless an emergency happens. The idea is that, whenever the system is not near rationing, the bids and the behavior of market participants should be the same that they would have been if there were no options; options are only relevant at the critical moments. This is achieved by setting a strike price that is high enough to only activate when the system is really sort of supply. Otherwise, it could be possible that a generator would be compelled to start-up, in order to avoid the penalty, without being really necessary.

Thus, this strike price should be settled at such a level that, under this "near rationing" scheme in which prices reach unusual high values, every generator in the system could recover his production costs. In principle, a way of assuring this would be to set the strike price to allow every generator to recover all his operating costs (including start-up and shut-down costs) in just one hour. This would probably mean to set the strike price at an extremely high level, what we would not recommend.

Hopefully, there are some aspects that suggest that the strike price should not be so high to allow a peaking unit to recover all his operating costs in just one hour. First, it is difficult to conceive that, in a "near rationing" situation, the reference market price goes above the strike in just one hour while the remaining hourly prices of the day stay at low levels. So, the peaking unit in most cases will be able to be scheduled in more than one hour, collecting additional income over its operating costs. On the other hand, the fact that the reference market is the day-ahead market (see section 3.2), eases the scheduling problem of a generator. Even in the worst scenario in which, after the day-ahead market, a generator were required to produce in just one hour, it is expected that the unit has had enough time to schedule his commitment and thus to fulfill his ramp rate constraints, especially since it should not be expensive to adjust his commitment in the balancing market.

However, the value of the strike price does have an influence on the spot market. Since all of the generators that have sold options in the long-term auction are willing to produce when the market price exceeds the strike price, to avoid the penalties, they will normally submit an offer to the market that is at most slightly less than the strike price. This way, they can be sure that they will be producing if the strike price is exceeded. This implies that the day-ahead price will very seldom be higher than this strike price —only when some of the committed generators fail to fulfill their production obligations—. Accordingly, the strike price is acting as a kind of price cap during the day-to-day operation of the power exchange.

In any case, the influence of the strike price on the remuneration of generators is not so critical as one could think. If the strike price is lower, then the bids in the capacity auction would detect that selling an option implies giving up to a higher amount of money during price peaks in the spot market and would ask for a higher premium fee; if the strike price is higher, then premium fees would be lower. This means that, although in practice the strike price has an effect similar to a cap to the short term market, the influence of its actual value on the remuneration of the generators is quite limited. In fact, the value of the strike price is just determining how much of the income that the generators receive will come from the energy markets —spot, futures, etc.— and how much of it will come from the capacity market. The higher the strike price, the lower the premium paid for capacity in the long term auction.

In order to avoid interfering with the energy market under "normal functioning", what would be inefficient, the variable cost of the most expensive peaking unit that might be reasonably required to serve load should be used to set the strike price. In The Netherlands this may be a rather restrictive condition, since peaking units are often forced to pay high unbalance penalties to the gas provider when they are required to operate in high demand conditions, and their actual operating cost is abnormally high. This would force the strike price to take a very high value or, otherwise, to preclude this kind of generators to take part in the reliability auction. Since these are precisely the generators that are more affected by the security of supply problem, the strike price would have to take a rather high value. Eventually, future reforms in the gas market regulation may tend to reduce these bidding prices, but nowadays the unbalancing penalty applies.

Accordingly, the strike price should be at least at the level of the marginal variable cost the regulator estimates as the most expensive in the system (as above stated, the regulator may decide to preclude some generators from participating in the auction). Additionally, to avoid the negative impact that an underestimation of this value could have, the strike price should be around 10-15% above of this value.

One of the arguments for a lower strike price is in regards with controlling market power. In a daily auction there is typically a part of the bidding curve where prices starts to rise more sharply. If the system is almost short of supply, the marginal generators belong to that part of the bidding curve, and firms perceive a very sharp slope of their residual demand curve; i.e., they can obtain important price increases with small reductions of their quantities. Thus, they have a great incentive to exercise their market power and make the system operate near that point where prices increase sharply. If the strike price is set under the point where slope increases, generators do not see the advantages of high price increases, and their market power is slightly reduced in the short term. Of course, this may make them try to exploit their market power in the capacity auction and ask for high premiums, but hopefully the long term market would be more competitive (see section 3.9.2).

However, this way of exercising market power is more typical from single-shot pools and, as far as we know, does not correspond with the behavior of the dominant production firms in the APX, so the argument cannot be applied in our case. In any case, setting a strike price that is devised to mute the part of the bidding curve with sharp slopes probably leads to a value of the strike price that is well below the cost of a peaking unit when its gas unbalance fees are considered.

Finally, it is very desirable that the value of this strike price remains quite stable along the years. Once a first decision is made, it should be maintained for the following capacity auctions and just updated considering some objective external references, such as RPI or international fuel prices. It is important that any of the references used to update the strike price is related with any magnitude that a generator can influence with his strategy, in order to avoid firms gaming with this process.

Summarizing, the strike price should be set around 10-15% above the value of the highest marginal operating cost of a peaking plant, considering the gas charges the regulator considers an efficient generator would have to pay. This price should be rather stable along the years, and just updated once a year with each new auction. This updating should be done using only a public formula, with RPI and international fuel prices, trying to make sure bidders are not able to manipulate it. So, the regulator should be careful not to use previous years' prices in the updating equation. Also, as discussed, it is important to notice that a modification in the rules of the gas market may justify a change in the strike price.

3.6 Demand side bids

Having a relatively low strike price could entail losing part of the demand response. The Dutch market includes a number of demand bids that are elastic to the price and whose prices are somewhat higher than the costs of a peaking unit —ignoring the gas unbalance penalty—. The reliability option mechanism would protect these elastic consumers from prices above the strike, so they would not reach the level of prices where it is profitable for them to stop consuming. Thus, a low strike price like this would leave out of the market these demand bids, reducing the economic efficiency of the solution of the final dispatch.

At the opposite extreme, one could then think of setting the strike price at the value of non-served load, trying to fully capture the potential demand elasticity. The problem with this solution is that it minimizes the income stabilization effect of the options mechanism. Having a strike price that allows to convert a part of the income that the units would have received from the price spikes into stable capacity remuneration is a useful tool that should be used whenever is possible.

However, there are some reasons that justify that long-term demand elasticity might be questioned. It looks rather obvious that the short-term price elasticity of loads can be under certain circumstances an efficient tool to contribute to the power system *security*. However, it is useful to wonder whether demand response should considered as a valuable supplier of long-term *adequacy*[9]. The reliability options market aims to put in place a new capacity-oriented product instead of just energy-based. Thus, it sets an incentive for new generation investments, but it is questionable if it would be reasonable (and if this would be the case, even viable) for the regulator to establish incentives for any consumer to significantly reduce its energy requirements or even leave the Dutch power system to improve the reserve margin. When a critical situation occurs, short-term demand elasticity would make self-rationing appear, so the shortage problem would be alleviated, but prices would still be high and consumers would also complain. Therefore, in the presence of risk aversion at least it looks like that short-term demand elasticity is generally an expensive way to provide adequacy.

The regulator has to decide whether the long-term demand elasticity that is required to contribute to system adequacy is truly a convenient factor for the future development of the economic activity. Maybe it is preferable that the regulators assume that demand is inelastic in the long-term, therefore avoiding to recur to mechanisms that could jeopardize the industrial or economic growth. However, one thing that the mechanism must take care in any case is to avoid losing the potential short-term demand response.

There is not a simple solution to fully ensure the two main concerns regarding demand participation: preserving the price signal for demand side bids and at the same time guaranteeing that the mechanisms will be effective in promoting new investment —it has to be safe from *free riding* and also safe from immature demand behavior—. As we will show next, any rule aiming to provide any further safeguard to prevent this latter issue entails certain inefficiencies in the short-term whose impact has to be pondered by the regulator.

The adopted reliability mechanism should assure that the demand side contribution to the system *security* is preserved —i.e. its ability to respond reducing its consumption in the short-term when needed to avoid scarcity events— but, without further refinements, the reliability options mechanism as it has been described up to this point would imply losing the potential demand response above the strike price.

[9] See discussion on the difference between these two terms in the introduction (section 0).

Without much conviction, we could expect that in any case, under tight capacity margins, generators have some incentive to agree with these elastic demands any load reductions before the day-ahead market, in order to avoid penalties. If in a tight margin scenario, option-holder generators with operating problems could detect a significant volume of these elastic demands such that they would be sufficient to prevent the reference market price from reaching the strike price, then these generators would have an important incentive to compensate the opportunity cost of the elastic consumers.

3.6.1 Allowing demand participating in the capacity auction

We could then consider allowing consumers to participate in the reliability auction by offering a kind-of-symmetric product. This way, a certain elastic demand d whose price p_d is higher than the strike price s could commit itself, in exchange of a premium, to release a quantity q_d whenever the spot price q reaches s (whenever $\rho \geq s$).

On the short term this solution bears the problem of having a fixed value of the strike price. This can result in the option-holder demands offering capacity in the spot market at a price —the strike price— that is lower than their true marginal utility, being thus inefficient.

On the long run, however, this alternative appears as an efficiency improvement. Assuming that its utility function is linear, the premium P_d of the elastic demand d would be its expectation on the opportunity cost of selling the option, i. e. its expectation on the time intervals $\hat{t}_{\rho \geq s}$ in which the reference market price will reach the strike price:

$$P_d = \hat{t}_{\rho \geq s} \cdot (p_d - s) \cdot q_d$$

If there is any consumer whose premium is lower than the most expensive bid of the last generator that would be accepted if demand would not be allowed to attend the auction, it can be stated that letting consumers participating in the auction contributes to the long-term system efficiency. Some generators are being replaced in the long-term auction by some demand side bids. Typically, demand elasticity is substituting some of the new entrants and the system is saving by eliminating the need for the new investment.

Unfortunately, this approach presents a major drawback: under these conditions it would be rather complicated to avoid gaming, since any demand could intentionally overestimate its future consumption in order to get an additional income for free. The market authority should supervise every demand bid to ensure this is not the case, what it would turn out to be rather controversial.

3.6.2 The reliability demand contracts

Aiming to fully solve this drawback, our proposal to involve elastic consumers in the reliability market is to design a specific *reliability demand contract*, which can be defined as a *physical knockout swap*. This product entails, for every hour of the year in which the day-ahead market price is lower than the reliability options strike price —which would as well be the *knockout price*—, the obligation on the seller to have a physical consumption in the energy balanced program submitted after the day-ahead market —see the settlement procedure discussion in section 3.1— which at least equals the quantity committed. Additionally, the contract involves a physical compromise of releasing whenever the reference market price reaches the strike price.

The product has two components: the first one, the *knockout swap* eliminates any gaming incentive related to declaring a fake demand, while the additional physical clause ensures the contribution of the contract-holder demands to the system security. At the same time, from the point of view of the option-holder generators, these consumers turn into an added factor to prevent the reference market price from reaching the reliability options strike price and thus triggering the penalty mechanism, what can result in savings for those generators that might be unavailable (and subsequently what might lead to lower bids in the reliability market).

The premium that a consumer d, which is willing to release if the market price is higher than p_d, would be its expectation on the opportunity cost of selling the *physical knockout swap*. Therefore:

- If his price p_d is higher than the *knockout* price —the options' strike price s — and his consumption profile corresponds to a plain base load throughout the year, the premium to ask in the auction will be obtained as expressed in the previous equation: $P_d = \hat{t}_{\rho \geq s} \cdot (p_d - s) \cdot q_d$.
- If his price p_d is higher than the *knockout* price but his demand profile will not always match the quantity committed in the reliability market, besides the aforementioned opportunity cost, he will have to internalize its expectation on the potential costs that balancing his energy program could entail —for instance, selling any left over in any subsequent market, such as the balancing market—. If the markets are reasonably liquid, this in principle should not represent a significant charge.
- Finally, if his price p_d is lower than the *knockout* price he will just bid at a very low price. He should just internalize his costs related to balancing his energy program, specially when the reference market price is between his price p_d and the strike price.

This approach contributes to the solution of the problem of incorporating the demand into the proposed scheme. Additionally, it seems to avoid gaming. However,

- It modifies the behavior of the consumers —or makes them to incur in costs— at times where there is no risk of lack of supply for the system. The procedure forces the consumers that sell this product to adjust to a fixed consumption pattern — first source of inefficiency— and to stop consuming when the spot price raises above the strike price, which may be lower than their marginal utility —second source of inefficiency—. The objective of preventing gaming is met, but at a cost that might be undesirable.

- It does not exploit the full potential of reduction of the consumers at the time of crisis in the system, since they can only bid into the auction their base consumption for the entire year. For example, some consumers could be able to reduce their demand to zero at the time of a crisis but could not afford to enter into the cost a *knockout swap* could entail.

3.6.3 Allocation of the reliability options to the individual consumers

Another solution, aimed to solve this issue, would be to implement the following procedure:

- The regulator buys to the generators on behalf of the whole demand a quantity of reliability options Q.
- Then, the regulator allocates a certain amount of capacity to each retailer/consumer, according to historical measures —this should be a sub-product of the reliability calculations developed to compute the total amount of capacity that is bought in the auction—. This way, eliminating the ability of demands to decide how much capacity do they want to buy, the regulator prevents free riding or immature demand behavior that might compromise long-term reliability.
  - Therefore, the regulator allocates a quantity of reliability contracts Q_d to each demand d.
- When the reference market price raises the strike price s, the demand d
  - pays the explicit penalty for every megawatt demanded over the contracted quantity Q_d —i. e. any consumer demanding more than the capacity allocated would not be protected by the options (for the extra amount)—, and
  - receives an extra income equivalent to difference between the spot price and the strike price, for every megawatt that its consumption is reduced under the contracted quantity Q_d.
- Any demand can claim an amount of reliability contracts higher than the initially allocated by the regulator.
  - The quantity allocated by the regulator acts as a lower bound, as well as the amount to buy in the auction from the generators acts as a upper one.

This way, every retailer/consumer perceives a direct income if he achieves to reduce his consumption in the critic periods. If a retailer/consumer is able to reduce his load in the rationing periods from the expected amount, he earns an extra income which is related to the penalty, while if it reduces its expectations, it earns an extra income which is related to the reduction in the capacity payments that the generator must do and, thus, it is related to the value of the premium fee.

Although it sounds similar to the interruptible contracts, this is less prone to gaming. On the one hand, consumers cannot decide how much capacity are they going to buy, but it is the regulator who decides so. Accordingly, consumers have no means to overstate their demand in order to obtain an extra profit. On the other hand, even if they could decide how many options they wanted to buy, the options are costly to acquire and this creates some costs in the long term auction that compensate the earnings that are obtained in the short term.

But it is still a very hard task with this method, which is the need to allocate the total capacity required in the system among retailers/consumers. Although it should be obtained as a sub-product of the general method to determine how many reliability options should be bought, it is a complicated and potentially controversial task. It shares some of the problems of the bilateral procurement of the options, and this approach also opens the door to a full-fledged implementation of the bilateral process. Our objections to this approach are discussed below in section 3.8.

3.6.4 A voluntary demand participation on the reliability mechanism

Finally, if free riding or lack of confidence on the demand's attitude towards long-term system adequacy is not a significant concern for the regulator, one should just let consumers decide how much do they want to buy in the capacity auction.

The only way to define a symmetrical way of treating demand and supply in this reliability options scheme is to give the consumers the freedom to contract reliability options or not. If they are forced to be protected from prices above s, they are from the outset in a different position than supply and we cannot fix that later. Therefore this desirable symmetry should be left only for "fully mature markets". A less liberal approach for demand follows.

Starting from the situation where all demand know that they will be protected from prices above s by the reliability options that will be purchased —for the complete demand— by the regulator, a consumer d may want to reduce its payment. And a possible way of doing so is by reducing the amount of capacity Q_d that is initially subject to the payment. In order to do so, the consumer pledges not to consume more than an amount of power Q_d^*, but only during the times of crisis where $\rho > s$, since he can consume any amount of capacity at any other times, subject to any other obligations (such as contracted capacity) that the consumer may have. If the consumer exceeds Q_d^* at the time where $\rho > s$, he will be subject to a fine equal to the explicit penalty —other alternative is an automatic reduction of the load to the prescribed level Q_d^* by the system operator or any other scheme—. Besides, the consumer d will lose the protection against energy spot prices higher than the strike price for any demand beyond Q_d^*. Note that this is a long-term commitment that is expressed by the consumer at the time of the auction of reliability options, for the same duration as the reliability options, and that it will have an impact on the volume of the auctions.

Since the regulator was assuming that the consumers would have a certain consumption pattern at the time of the high prices, the commitment of the consumers limiting its consumption at that time will modify the quantitative basis of the regulator to make his assessment, and this should reduce somewhat the volume of firm generation capacity to be requested.

This scheme does not seem to be subject to gaming. The regulator only cares about Q_d^* and, therefore, any previous declaration or commitment to Q_d has no influence whatsoever. Free riding issues are discussed below.

The potential drawbacks of the approach would be:

- It is voluntary for consumers, so maybe only few of them will participate. Perhaps the drawbacks of the commitment will be perceived as too strong when compared to the savings in the reliability options charge.
- The opposite may be also true. Consumers may believe that crisis will never happen and therefore many of them could participate in thus mechanism pledging a very low value of Q_d^*. Then, the remaining consumers will have to pay, in principle, the bill of the reliability options scheme. This might appear as a form of free riding. However, if the regulator acts in a consistent manner, he should request a lower value of firm generation capacity from the long term auction and the per-unit charge to consumers for the reliability options scheme will remain more or less the same, and the consumers requesting protection will continue being protected. A consequence of this may be that the price of the auction will be very low, as there will be excess supply, at least initially. In the longer term it might happen that the spot price raises above the strike price more frequently. While there is a surplus of generation capacity the free riders will enjoy protection at no cost, since prices will not go beyond the strike price.

  The approach may be considered as a transition towards a "mature market" but also as a dangerous way of allowing more and more demand to become exposed to a potential lack of supply, even if it is voluntarily. The possibility for demand bidding could be restricted to large consumers and therefore it will be like an advanced format of interruptibility. Also, one may want to introduce some difficulties for consumers to switch back and forth from relying on the market and being protected by reliability options.

- It requires the regulator to make explicit the procedure to determine how much each consumer will be charged because of the protection provided by the reliability options. But this has to be done, anyway.
- Ideally it requires the regulator to have an explicit method to take into account the reduction in generation firm capacity that corresponds to a reduction in expected demand. But, again, the regulator must have some means of estimating the requirement of firm generation capacity anyway.

3.6.5 Conclusion

After taking into account the advantages and disadvantages of all of the former alternatives, we propose to use the following approach that combines features of most of them:

- Demand side bids should be used as short-term security resources —to reduce consumption when the system is short—, but not as long-term reliability elements —they should not replace the need to build any new generator—. However, this is a policy decision that may be changed by the regulator (see alternative design below).
- Initially, only large consumers are allowed to participate. This allows to capture a big volume of demand elasticity while keeping implementation details reasonably simple. Some opportunities to exploit demand elasticity are lost, but implementation would have been very difficult otherwise.
- The regulator calculates a minimum value for the capacity that each of these large consumers must buy. This computation is not easy, but can be accomplished for the large consumers using the same process where the total amount of reliability options is determined. Doing so for smaller customers is much more complicated. The consumers may decide to buy some more capacity. In any case, this capacity is bought through a centralized auction organized by the regulator, together with the rest of the capacity that is required for the year.
- If, during a certain hour when the spot price is high, the consumer demands less energy than committed, then he receives a reward. If, during those critical times, he consumes more than the capacity contracted, then he receives a penalty. Both the reward and the penalty are equal to the explicit penalty of the reliability options plus the difference between the spot price and the strike price.
- For the rest of the consumers, the regulator calculates the aggregated value of capacity to be bought for all of them, and as a result of the procedure they are fully hedged from the price spikes in the spot market.

Under this scheme, large consumers are fully exposed to the spot prices, so the incentives for them to react to the prices and to reduce their consumption when these are high remain complete. At the same time, a minimum value to the capacity they should buy in the long term is established in order to avoid any potential discrimination against the domestic consumers or any potential free-riding problem. Since large consumers can not determine how much capacity do they want to buy, no gaming opportunities arise for them.

If it is important to have the demand playing a role also in the investment decisions and, therefore, to allow for some peaking units being replaced by demand bids, then the procedure should be changed so the regulator would not calculate any capacity requirement for the large consumers. They would freely decide the amount of capacity they want to buy. Thus, their ability to reduce their load would directly imply a reduction in the capacity that is bought in the auction and they will be effectively replacing some production side bids. The rest of the procedure would remain the same.

3.7 Duration of the options

One of the critical parts of the auction procedure is to encourage the participation of new entrants. The time horizon of the options is one of the most relevant elements to achieve that objective. This horizon is divided into a lag period, where no obligations apply, which starts the moment after the auction is held and finishes when the option starts to generate obligations, and the option duration period, or binding period, which happens after the lag period and is the time when the generator has to produce whenever the spot price goes above the strike price or otherwise he would be penalized.

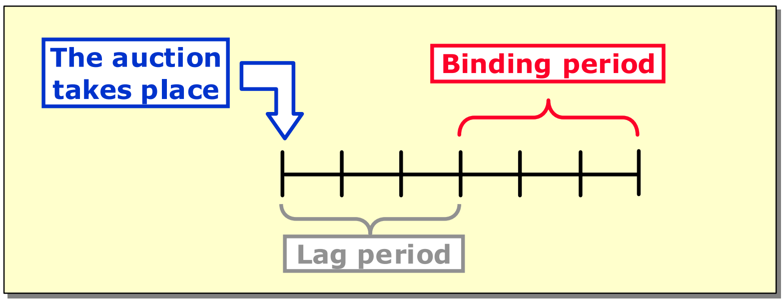

Fig. 4. Time horizon of the reliability options

The duration of the lag period is devised to allow for a new entrant to build his plant after he has won the auction. We recommend to use two years, since most gas generation units can be installed in that time. Of course, this means that the new entrant would have to start the administrative procedures (sitting, permissions, etc.) much before, but these are tasks that do not involve great investments and can be considered as a low entry cost. On the other side, the existence of the lag period allows the firm not to start building the plant until it is known for sure that he will be remunerated, because of the option he has sold — although this will only cover partially the investment expenses—.

Regarding the option duration period, new entrants would like to have very long time ranges of secured premium payment, which is the least risky solution for them. However, it is interesting for the regulator to have an auction run every year, in order to meet the new needs for capacity and to avoid that unexpected results at a certain auction may carry dramatic results for a very long period. Furthermore, the old existing generators would typically want short option duration periods, since they have considerable uncertainty about their future performance and committing to produce at distant dates is conflictive for them.

There are several alternatives to try to combine all of these interests. One possible solution, consists in having long option duration periods —to favor new entrants— but splitting the market into several parts in order to have auctions once a year. Fig. 5 shows an example with five years of option duration, that would require five different auctions, each of them buying 20% of the demand.

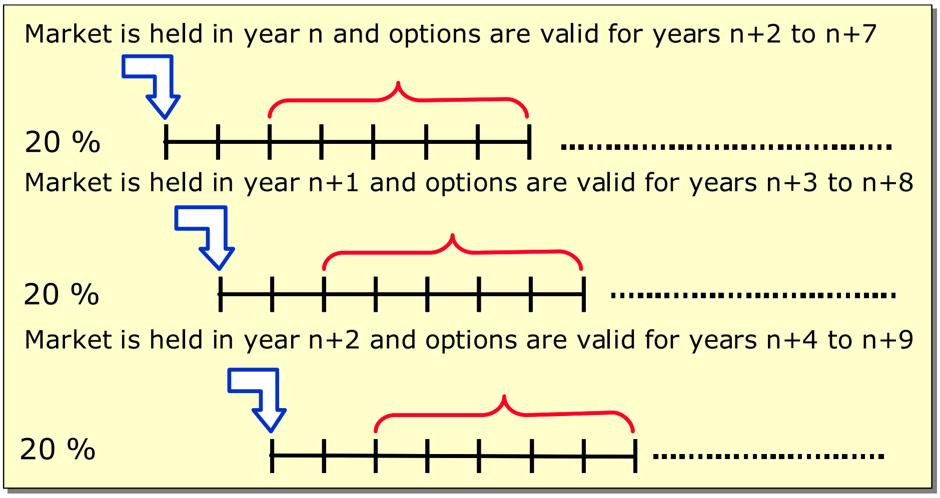

Fig. 5. Long option duration + market splitting

The obvious problem with this solution is that it requires to fraction the demand. Thus, the capacity market becomes thinner, with less amount of supply and demand, and the results of the auction may become more controversial. For instance, it is easier to manipulate the results and, in general, the procedure becomes less attractive for bidders. Besides, some opportunities of arbitrage between the different markets appear and it is possible that some chances for gaming emerge associated with them.

Another possible solution is to have auctions just once every five years, so the option duration period could be enlarged at the expense of having fewer auctions. This is conflictive for the authority that organizes the auction, who loses flexibility to incorporate his new needs, but may be also conflictive for new entrants, that are forced to plan with considerable anticipation their entry decisions in order to be ready to participate to the correct auction. Besides, it is extremely conflictive for the old unreliable generators that already exist in the system, for whom any commitment for a long period increases their risk instead of reducing them, because of the uncertainty in their performance. One should keep in mind that these old plants, close to retirement, are also a target group for the security of supply mechanism, which should provide incentives for them to stay in the system and not to retire. A very long option duration period penalizes these groups.

Finally, another alternative consists in defining a one year duration period for the existing generators and allowing new entrants to choose between the standard one year period or a longer five years one. This does not affect the auction procedure, since only price and quantities are considered when determining the result of the auction, and is only related to the question of for how long is the commitment valid. An auction will be held each year, for a large part of the demand —where only a small fraction corresponding at most to the volume of new capacity accepted during the last five years— would be left out of the auctions —since these options have been already assigned—. Once the five years period expires, the generator is considered an existing one and is only allowed to obtain options with one year duration.

This alternative may create some asymmetries between bidders. The existing generators are making one year bids and are considering for that their estimations on the evolution of prices during the relevant year. On the other hand, new entrants will be typically bidding for a five year period and they will be using in their bids their hypothesis on the evolution of prices during the whole five-year period. However, both products are auctioned at the same time and both receive the same prices. We are assuming that the value of the option will be the same for every year. However, we think that this simplification would not be so dramatically different to reality. Considering that there is a two-year lag period, uncertainties on the evolution of prices would typically make the estimations of prices for year n+2 very similar to the estimations of prices for year n+4, for instance, especially regarding the estimations of price spikes.

However, if these estimations happened to be different, the new entrants that are willing to sell five-year options would have to make a bid for something similar to their average capacity price for the five years. The price in this capacity market would be typically close to these bids of the new entrants, so incumbents will be competing against a screening average price. Since this is a proxy for long term-marginal cost, this additional stabilization factor seems to be a good element in the result.

This solution seems to combine the requirements of both the new generators and the existing ones with no relevant drawbacks, and it seems to be an acceptable compromise.

3.8 Bilateral procurement

An alternative to the auction of the reliability options could be to impose on consumers or retailers an obligation to acquire the reliability options. This would eliminate the need to establish administratively the duration of the options and would allow the market to determine whether the most suitable definition of the option contract should be five or seven or any other number of years. At the same time, this would make consumers adopt a much more active role in finding generators to provide the reliability options. It should mitigate the problems related with liquidity in the long term market, which is one of the critical problems of the mechanism.

However, making it bilateral also bears some problems and we do not recommend using this approach in the context of the Dutch market. On the one hand, this kind of mechanism poses most of the pressure on the default tariff setting mechanism. As far as we know, the philosophy underlying the Dutch tariff is some yardstick competition where each retailer receives a part of his own cost for acquiring the energy and a part of some reference cost —typically the average of the cost of the remaining retailers—. This has the obvious problem that retailers may claim having paid high prices in order to raise the tariff. So most of the process relies on the ability of the regulator to control these kind of gaming and new difficulties may appear with a new product for which it may be difficult for the supervision authority to clearly determine a reasonable price.

So the problem of market power seems to unfold in two: the potential lack of new entrants that we already had and that may remain —perhaps somehow reduced— under this new solution, and the potential for gaming, which is new and depends basically on the tariff setting mechanism and on the supervising abilities of the regulator. Whether this is a major obstacle or not depends on the regulator's view of his own supervising capacity[10].

On the other hand, there are some other problems that relate to the interaction between the capacity obligation and the retail market, under full retail competition. The first of these questions is the difficulty to estimate the demand for a retailer. It is always easier to estimate system demand than the demand for a certain area or for some large consumer. However, we could think that this is something that can be technically done with greater or lesser accuracy. But estimating the demand of a certain retailer implies also estimating his market share on the retail market, and that is much more complicated. The need to allocate capacity obligation would force the regulator to make public his estimation on the evolution of the retail market, which is always subject to a certain aggressive advertisement or pricing campaign that can change radically the view.

And, at the same time, there is a question with the different timing of the supply contracts and the reliability contracts. When there is retail competition, and retailers are forced to

[10] Recent moves in the Dutch market to completely eliminate the regulated tariffs would make this objection irrelevant. The potential abuses regarding the prices for capacity will be in theory limited by the competition among different retailers. Thus, the problem of controlling those abuses is the same problem than controlling abuses in the energy prices, which exceeds by far the scope of this work.

buy options for all of their demand, and options may cover several years, then the question is which is the demand for each retailer.

If checking the obligation *ex-ante*, the regulator may have difficulties in estimating the market shares of the different suppliers. Even with some kind of *ex-post* checking, it is still hard to determine what is the demand in the year for which the capacity obligation is computed. If the maximum capacity is used, then every consumer that leaves the retailer leaves him with some spare capacity obligation that he bought and he does not need anymore. We would not like to have a short-term market for capacity —as in PJM, for instance—, because this eliminates part of the price stability of the product and tends to lead to a much greater volatility in the market. Typically, the price would be very low for a large part of the year and very high when the system is under pressure, being rather similar to an energy only market.

If we allow each consumer leaving the retailer to take his capacity with him, then the new retailer may be forced to receive a contract that someone else signed and that he may consider to be expensive. In fact, the most convenient solution if we want the consumer to migrate with his capacity rights is to have them bought in a centralized way, so they become independent from the suppliers.

Finally, a minor problem with bilateral procurement may be the question of enforcement. If the options are not public, but bought through a bilateral process, it seems that some retailers may decide not to buy any option and sign a contract with the final consumers where the whole spot price (with no option) is passed-through. If the freedom to choose supplier includes the ability of supplier to leave consumers away from the benefits of the reliability options —or the ability of consumers not to buy them— then the procedure will hardly work. This could be solved by the regulation imposing conditions on the supply contracts. For instance, declaring illegal to charge them above the strike price, but it seems harder to control. This can be done for either centralized or bilateral procurement, and similar problems may arise, but it seems to us that supervising the centralized model may be easier.

In general, it seems easier in this first implementation to start from a centralized procurement of the options and wait for the scheme to be more consolidated before considering making it bilateral. Specially in the Dutch case, where there are plans to become part of a broader pan-European scheme —which would probably be based on bilateral procurement—, retailers should not be asked to engage into contracts in a context of high regulatory uncertainty. This may lead to high purchasing cost. In this context, probably a regulated centralized procurement and a regulated duration of the contracts may be more advisable, at least until the pan-European scheme is completed.

3.9 Market power

3.9.1 Basic procedure

Although the options have a number of effects on the daily market, the major part of the reliability-related business happens in the capacity auction. This auction —which is typically set once a year (see section 3.7)— determines the price for capacity, corresponding to the last accepted bid.

The bid price of any generator will include the expectation on the future costs derived from the contract:

- The opportunity cost due to the income cap imposed by the option strike price, which equals the value of the lost income when the spot price goes above the strike price.
- The amount of money the generator has to pay back to the consumers due to the explicit penalties when he is unavailable.

Some generators may include an additional term in their bids. On the one hand, new entrants will require to ensure a sufficient remuneration to go on with their investments; on the other hand, plants that might be considering leaving the system because they do not cover their operating expenses from the spot prices, will require and additional income to pay for their operation and maintenance costs or otherwise they would leave the market. This additional term would be the difference between their total market income and their total costs (per year), including operation and capital costs for the new entrants and just operation costs for the plants potentially closing.

Attending to these considerations, we can expect three basic kinds of bids (see Fig. 6):

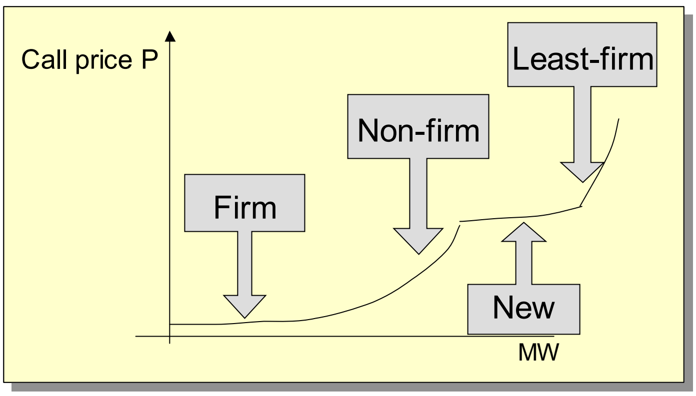

Fig. 6. Typical aggregated supply curve

- Firm energy
  The most relevant part in the bid price of those existing and "firmer" plants —for instance, those characterized by a low forced outage rate— is the lost income that derives from the option strike price. Due to their high level of reliability, the

relevance of the explicit penalty is not very significant. Therefore, the expected bid price of these plants will be low.

- Non-firm energy
  For those generators that have more difficulties to fulfill their reliability obligations, since their chances to be unavailable when prices are higher than the strike price are relevant, the expected costs due to penalties will be higher compared with the firmer generators, while the expectation of the lost income remains approximately the same. Thus, the relative relevance of the penalty is much higher and also their bid prices become higher. Note that this includes both the units that are cheaper than the new entrants and the ones that are more expensive than them and, thus, will be normally rejected in the capacity auction.

- New entrants
  Finally, the most likely situation of new entrants will be to be on the margin at the capacity market. Since they are new generators with low failure rates, the importance of the opportunity cost related to the option strike price is high, while the compensation and penalty are relatively small. But, as mentioned above, they have to internalize an additional term to bolster up their expectation to get enough return from their investment.

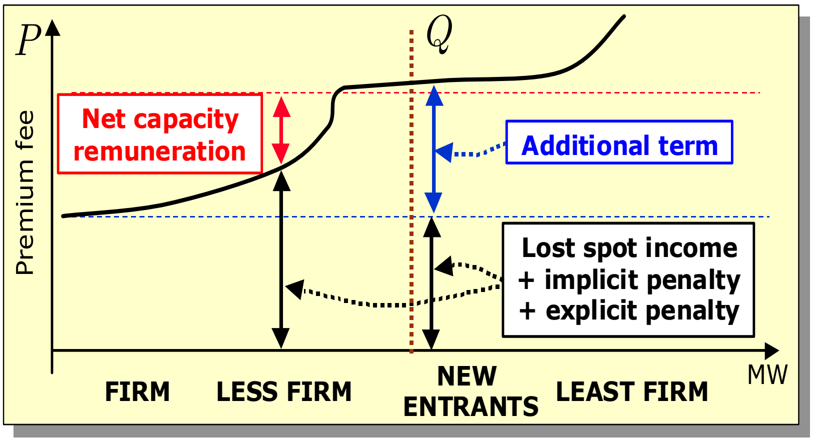

Fig. 7. Components of the premium fee

From Fig. 7 it can be noted that the net capacity remuneration for a certain generator is just determined by its firmness. Competition among energy blocks (generators) is governed by the degree of firmness (reliability) of each block and it is not influenced at all by their operating costs.

In general, we are assuming that there is an almost-infinite supply of new entrants participating in the capacity auction (see section 3.9.2 below). Thus, the price level where entry starts being profitable tends to act as a price cap in this long term market. Even if the incumbent generators have some amount of market power, they will have difficulties trying to manipulating the capacity price if there is a relevant amount of new units ready to get installed if they are paid properly.

Let us distinguish two cases regarding market power abuse: In the one hand, when the system is expanding and new generation is required, then the competitive outcome —price— of the auction will be determined by the bids of the new entrants. When, in this situation, the incumbent generators withhold some capacity they have to bear two different problems: first, they are missing the opportunity to sell some reliability options and make an interesting deal; second, they are allowing new generators —potentially competitors— to enter the system. But in exchange incumbents cannot almost obtain any relevant raise in the capacity price, since there are many similar bids of new entrants participating in the auction, and all of them are ready to replace the capacity that the incumbents withhold. Even if the existing generators have engaged into long-term bilateral contracts with consumers that ensure them enough revenue to recover their investments, if they decide not to participate in the capacity auction they will be leaving room for their competitors —specially the new entrants— to get into the system, and that seems to be a poor strategic movement for the incumbents.

On the other hand, when the system is in a situation of excess generation and no new units are required, the competitive outcome of the capacity auction will be determined by the bids from the existing generators. Incumbent firms with some kind of dominant position can manipulate the market and raise this price. However, they cannot raise the price above the level where new generators start entering the market. Therefore, finally the existence of market power makes the system pay always the price required by the new generation. Considering that can be typically considered as a proxy of the long-run marginal cost, the effect of market power is just to smoothen some fluctuations in the capacity price that may arise if investments in generation are not perfectly coordinated in time with demand growth, but apparently it just has a stabilization effect on the capacity price that is not especially harmful.

Of course, all of the former arguments are totally based on the idea that there is a large supply of new entrants ready to get installed if the capacity auction determines that they are necessary, and that the prices that all of them would ask for doing so are relative similar. Otherwise, market power may arise in the capacity auction and this is surely the major threat for the proper functioning of the reliability options mechanism.

3.9.2 Liquidity in the capacity auction

The previous reasoning illustrates the capital importance of new entrants in the proposed design. Having a higher level of competition in the long run is the only way in which we handle the problems of market power that may exist in the short term. New entrants are required both as a means to control the oligopolistic behavior that incumbents may present and because, in many systems, most of the time there is no spare firm capacity available and the most probable situation is that the bids from existing generators are not enough to cover the amount of power that the regulator is willing to buy in the capacity auction, or that they merely equal it. This may lead to situations of extreme market power exercise if only existing generators compete in the auction. Even if the incumbent firms are willing to construct new plants, the margins between supply and demand in this market are necessarily too tight when no new firms participate, and one should be aware of the prices that may result from that kind of market.

Thus, it is a key element for the functioning of this mechanism to have a relevant amount of potential new entrants participating in the auction. Only if there is enough competition among new entrants, suitable prices can be obtained and the security of supply mechanism can lead to an efficient result. It is critical for the method as a whole to have a wealthy amount of new entry candidates to foster competition in the capacity auction.

There are several elements that may allow us to be slightly optimistic in this regard. Firms can participate in the auction before they have build their plant —see section 3.7—, so they do not have the risk of not being accepted in the auction and thus losing their investment. This tends to facilitate the investment decision. On the other hand, building a peaking plant once a reliability option has been awarded is a reduced-risk business. A stable amount of income is guaranteed during the first five years, which use to be the critical period when deciding to construct a plant, and it is the firm itself who has determined how much did he need to get installed. Also, for the remaining years in which the unit is in operation, there is a reasonable perspective of having some equivalent fixed income, determined in a year-by-year basis but probably rather stable. It seems that this should be enough to attract investors, ranging from classic power companies to investment banks.

It should be noted that new firms can, in principle, bid the price they want for their capacity and that this would typically cover most of the investment costs of a peaking unit. For any firm, building a peaker once he has obtained an option is a business with much lower risk than any other investment in electricity generation, so it seems that it would be attractive and several new participants would arise. The competition among them would set prices at efficient values.

Therefore, a fluent amount of potential new entrants is a critical requirement for the mechanism. However, it is not essential that all of these new entrants actually get installed; an entry threat may be enough to obtain a near-competitive result. In any case, it is important to check if there are any significant entry barriers in the system that may difficult this. Two potential problems have been mentioned during the discussions held along this project: the competitive advantages that incumbents have since they have better access to sittings, and the lack of liquidity in the balancing market, that favors large players.

Both situations tend to widen the difference between the investment cost for incumbents and the investment costs for new entrants. Since the capacity price that results from the long term auction will be rather close to the price set by new entrants —assuming that incumbents have some market power—, the margin that oligopolistic generators may obtain gets larger. This is something that would be interesting to solve, probably regardless of the reliability issues. However, its effect as an entry barrier will also happen with no reliability options and it also makes entry difficult new nowadays. We think that the cost of the new entry, which is the element that we are using here to control market power, is not increased by the capacity market, but reduced.

Additionally, there should be a special interest from the regulator (or the TSO) to encourage participation of new entrants in this auction. In fact, there should be an active movement from the authorities to ensure that interested bidders will appear in the auction, in terms of publicity, advertisement and actually contacting the potential participants to encourage them to attend the auction.

If this is not possible —i.e., if the regulator cannot attract enough new firms to enter the market— then it is a clear symptom that there is something in the design that is not working properly and the auction should not be held. In general, the potential to obtain new entrants in this market should be evaluated before putting the reliability options mechanism in place and, hopefully, great differences in the behavior of the parties should not arise in the following years. In any case, if at some intermediate moment it is detected that the capacity auction will not be competitive enough, then it is not a good idea to adopt a competitive procedure. Some other regulated alternative should be used instead, either based on the reliability options —such as imposing a tight price cap on the capacity auction and somehow force incumbents firms to participate in this market— or through a more classical method —such as capacity payments or any other similar procedure—. Another way of thinking regarding this question is to adopt the bilateral procurement design discussed in section 3.8, which forces the parties in the market to become more active in the quest for new entrants in order to fulfill their capacity obligations, but this also presents some problems as described in section 3.8.

As a summary, the regulator should perform an active advertising role before the auction is held, and should try to know in advance that a relevant number of new entrants would attend the auction. Otherwise, it may be problematic to run the auction.

3.10 The amount of capacity to be bought

3.10.1 A single quantity

The long-term capacity auction where the reliability options are bought and sold is one of the central elements in the design. When resolving this auction, the regulator needs to know the bidding curve provided by the generators and how many reliability options should be bought at the auction. In order to obtain this second figure, the most direct approach is that the regulator himself determines a certain volume of capacity, which is announced well in advance to the moment when the auction is held and which is part of the conditions that define the capacity market —i. e., the conditions that every potential bidder receives and considers when preparing his participation in the capacity market—. This capacity is obtained from classical reliability studies, equivalent to those that were performed under the traditional regulation to determine how much generation was needed in the system. It reflects the volume of power that is required to be installed in the system in order to fulfill a certain level of security of supply.

Ideally, one would like to set this quantity equal to some value representing the maximum peak load that is expected for the year plus some reserve margin. But this would only be suitable if the generators would bid only their firmest capacity —meaning the capacity that is 100% reliable— into the auction. Generators that are subject to partial outages will tend to divide their capacity into bidding blocks, so the more reliable ones will have lower prices in the auction. This is typically the case of hydro units, and here the capacity auction tends to select very form blocks. However, thermal generators are also subject to discrete failure events, where they can only be either completely available or totally unavailable. They cannot divide their capacity into blocks to reflect this kind of outages, so they would tend to bid their whole generating capacity into the reliability options auction. Thus, when buying the reliability options, the regulator must consider that the product he is acquiring is not perfectly reliable, and that these groups have a probability of not being able to produce when required. In order to hedge against these cases, the regulator may want to buy some extra capacity to ensure the desired level of reliability.

This calculation requires, in order to be accurate, to know in advance the (expected) level of reliability of the different generators. However, the System Operator can make use of estimations about the forced outage rates of the equipment installed in the system to obtain this figure and it does not seem difficult to get reasonable approximations to these failure rates. If the generators installed in the system do not change radically, these calculations can be translated into a certain percentage above the peak demand that will keep relatively constant as long as the generation mix remains basically the same. Besides, it is important to recall that these estimations are just required for the computation of the total power required in the system; each generator will define by himself his own position in the supply curve for the reliability options through his bids, so the System Operator calculations will not influence the allocation of the options among the producers.

In conclusion, it is accepted that the System Operator estimates, using classical engineering procedures, a total figure for the amount of capacity required in the system to be as reliable as desired. This is the amount of reliability options that are bought at the capacity auction.

3.10.2 The problem of indivisibility of the generator bid blocks

All along the report, we have stated that, whenever it is possible, the mechanism has to try to facilitate the generators' decision-making process in order to minimize undesired uncertainties that might lead to risk aversion and thus to inefficient bidding behavior. Therefore, it would be suitable to include an additional consideration. The amount of capacity to be bought is publicly set *ex ante* in order to allow the generators, particularly the new entrants, to better estimate the proper premium to be asked for in the auction to ensure that the obtain a satisfactory remuneration for their investment.

However, if the risks for generators are to be reduced, they should be guaranteed that once the auction is cleared, the marginal bid will not be partially accepted. If this would be the case, a potential new entrant who bid a certain capacity q, corresponding to the capacity of a potential production plant that he is planning to install in case of winning the auction, could happen to be the marginal generator and, thus, could happen to be partially awarded some reliability options, for a capacity $\tilde{q}$ lower than q.

This would compel him to invest in any case, since otherwise he would be in trouble when the prices of the spot market were high and he were required to produce up to $\tilde{q}$. But, on the other hand, he will be only receiving a portion of the required capacity remuneration. Since it may not be obvious to build another smaller plant, the firm will be losing a part of the income that he needed to be able to recover his investment. This is a risks associated to the rules for clearing the auction that should be avoided.

Thus, we propose to use a fixed amount of capacity Q to clear the long term market, but to make it somehow flexible, in order to avoid dividing any accepted bid. The auction will always buy a capacity greater than Q; the minimum volume that allows not to divide any bid (see Fig. 8). Note that when several bids with the same price are marginal, some of them may be accepted and some of them may be reject, attending just to their sizes. We recommend to define a clear priority rule —typically, the smaller (more flexible) bids will be accepted first— to avoid any concern on the equity of the auction. Also, in order to avoid any potential gaming, this rule may be complemented with a maximum size for the indivisible bidding blocks —blocks that are larger will be divided—, corresponding to the typical size of a peaking generator.

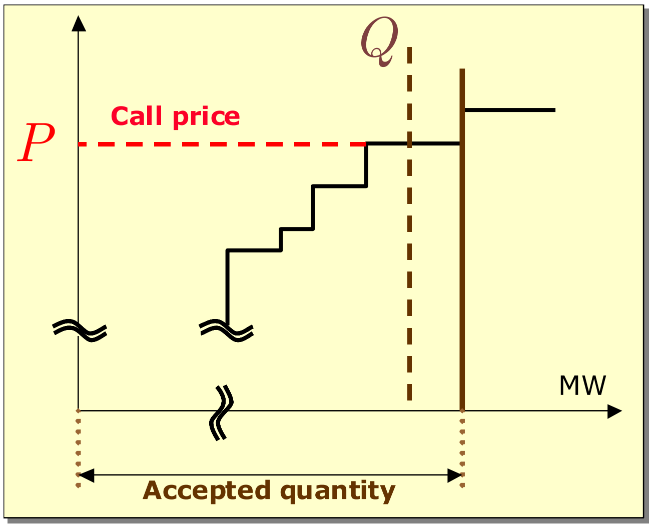

Fig. 8. Marginal bid indivisibility

3.10.3 An indefinite amount of power

One of the alternatives suggested for this auction consists in not declaring the volume of reliability options that the regulator wants to buy. Of course, the System Operator should have calculated the amount required, as in the previous section, but the regulator does not communicate it to the firms participating in the auction. If the prices happen to be higher than expected, then the regulator keeps the possibility of reducing the amount of options he buys, or even suspending the auction and try to buy them in some other place. If the prices result to be lower than expected, the regulator can even buy more than required and acquire an extra protection for consumers.

This seems to be a good deal for the regulator, who keeps some extra flexibility, but represents a major problem for bidders. The value of the reliability option depends on how many hours will the spot price (and/or the balancing price) exceed the strike price. If there are many generators contracted through the options, then they will all contribute to have few periods of high prices, but if the volume of option-holders is much lower than the expected volume of consumption, then the reliability option becomes more expensive. The generator who is preparing his bids to the capacity market would like to contrast his expectations on the demand growth with the volume of options that the regulator is buying, and that information is rather important for his estimations on how much would he require in exchange of his reliability option.

If that information is hidden, the generator will have difficulties calculating the price of his option and, due to risk aversion, would tend to set a high worst-case price. Generally speaking, auction theory shows that in any auction the auctioneer is able to obtain better results and extract more surplus from the bidders if he reveals as much information on the conditions of the auction as possible. For instance, the regulator should also disclose his estimations on demand, import capacity, etc. If this information is not declared, it becomes an additional factor that bidders have to estimate and tends to lead to more expensive results —because firms tend to use worst-case conditions— and less efficient outcomes —because not everyone is able to do accurate estimations, and some may have errors that make them bid too low or too high—. Announcing the amount of capacity that the regulator will buy in the capacity auction facilitates the market to reach a better solution and, from the buyer's point of view, allows for lower prices in the bids.

3.10.4 A demand curve determined by the regulator

Trying to capture the former flexibility spirit but avoiding the uncertainty of the previous proposal, one could try to set a demand curve for capacity. This means that the regulator would commit to buy a certain volume of reliability options for a certain price —based on his estimations of the results of the market— and to increase in some degree the volume of options bought if the price happens to be lower and, symmetrically, to reduce the quantity bought if the price is high.

This reveals the information that the regulator will use to decide how much to buy, but keeps some flexibility. The problem with this solution is that it provides excessive signaling for the generators. In such a long term market, there is considerable uncertainty about the prices that the generators would bid. 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 fact, it is a situation where tacit collusion appears very easily; without having to talk one with each other, skilled bidders would realize that it is quite probable that the auction will yield the same price that the regulator has estimated and would not be willing to sell for less.

The buyer should disclose as much information as possible that allows bidders to estimate the costs they will incur —to allow for more efficient bidding—, but he should not reveal his own willingness to pay —otherwise he would be facilitating the exercise of market power—. This alternative does not seem suitable for the capacity market.

3.10.5 Conclusion

Considering the previous arguments, it seems that the simple solution of just asking for a fixed quantity, known *ex-ante* and computed through classical reliability standards, and only modified to avoid the partial rejection of some bid, is the most reasonable solution.

3.11 Safeguard conditions

One of the salient features of the options procedure is that generators have strong incentives to bid their best estimation of their firm capacity —or, more precisely, their production during the critical periods—. In case they commit an excessive amount of capacity and they cannot produce that amount of power during the high price periods, the units will be heavily penalized. Therefore, it is not efficient for the generators to sell more power than their real firm capacity.

Accordingly, the regulator should be willing to accept any bid that is presented into the auction. But the question arises when the regulator receives a certain bid that, in his perception, is obviously flawed, so the bidder will not be able to fulfill his obligations and would incur in severe penalties. From the regulator's perspective, the penalties received do not compensate completely for the problems caused by the shortages. And, furthermore, the penalties that the bidder will have to bear may be so heavy that they may bankrupt the firm, so consumers finally will not receive that compensation. Should the regulator accept this bid?.

The alternative solution is to establish a set of rules aimed at defining how the generators should bid in this market. This has the problem of interfering with their free commercial decisions of the generators and go back to the times of traditional regulation. There is a trade-off between not imposing any additional rule, therefore completely relying on the economic incentives, —so there is a risk that very aggressive (or inefficient) bidders may increase the risk of a blackout—and imposing too many safeguard rules, distorting severely the market and the ability of the generators to make their own decisions.

We recommend to use some safeguard conditions, but only when it is extremely obvious that the bid presented is too risky or simply flawed, and not to use safeguard conditions whenever there is a commercial decision involved that cannot be directly identified as unacceptable.

We recommend to use the following two rules:

- No generator should be allowed to bid above its name-plate capacity. Otherwise, the option will not reduce his risk, but it will increase it and, more important, the generator will not be providing firm energy to the system. Although he would be penalized if the system experiments troubles, the regulator is not looking for an economic compensation, but for avoidance of the physical rationing. This safeguard condition excludes financial trades to participate in the auction unless they are physically backed by an actual power plant.
- Some kind of financial guarantee should be required in order to participate in the capacity auction, to make sure that the generator will be economically responsible for the penalties that he may bear.

We do not see how to impose a safeguard condition related to the gas contracts. It seems that, for a peaking unit, contracting gas is a very important decision and they have to choose between an expensive but flexible contract or a cheap contract and high unbalance penalties. This is a decision between a high fixed cost or a high variable cost, which depends on the expected usage of the resource —in this case, the flexibility— and this is a rather complex task. It does not seem suitable that the regulator requires the generators to sign some special type of contract, because he would be seriously interfering with their decision.

We do not see either any reasonable safeguard condition related to cooling restrictions. Again, it involves a complex decision problem that should be left to the economic incentives in order to avoid an undesired interference.

Finally, the most conflictive situation regarding safeguard rules is the case of the new entrants. The system is designed to encourage new generation, and they are allowed to participate in the auction even before existing. On the other hand, this seems to be risky for the regulator. For instance, it may happen that a new entrant's plant is accepted in the capacity auction, then the generator starts to build the plant, but there are some delays and the unit is not in place when the lag period ends. This is a problem for the regulator, who ends up with e a system with underinvestment and gets exposed to a major shortage problem.

We agree that there is an extra risk associated with bids from generators that do not yet exist, but the need to encourage entry from this kind of generators —not only under the reliability options model, but in general— is so urgent that compensates the risk. The regulator can, however, reinforce the economic incentives to try to make sure that the new generator will be on line in time. On one hand, the plant should not be paid the corresponding premium fee until its installed name-plate capacity exceeds the committed capacity but, on the other hand, strong penalties should be imposed for each day that the generator is late in being on line —these penalties could be detracted from the guarantees required at the moment of winning the auction—.

4. Summary of the proposal

The implementation proposed for the reliability options mechanism could be summarized in its more general expressions as follows.

1 The regulator has to set the following values:

1.1 The strike price.

It should be around 15% above the typical variable cost of the most expensive unit that is reasonable to have operating in the market. In the Dutch market, if it is a reasonable strategy for a peaking unit to pay the gas unbalance penalty when it is required to produce at tight demand-supply conditions, then this extra cost should be considered as a part of its operating costs for this computation.

1.2 The total amount of capacity he wants to buy.

This should be obtained through classical reliability procedures and represents the amount of installed capacity that the system requires to have the desired level of reliability. This number also includes the capacity that may be contributed by imports.

From this figure, the regulator should deduct the volume of options already assigned (corresponding to new generators that asked for five year options).

For large consumers, the regulator must also determine the amount of reliability options that he allocates to each of them.

1.3 The time scope of the auction.

We suggest to have a lag period of two years and an option duration period of one year. This means that if the auction is conducted at the 1st of January of year n, then the option will be enforceable from the 1st of January of year n+2 to the 1st of January of year n+3.

For generators that are new in the system, i.e., that are not already installed when the auction is conducted, they may opt to have a five years duration of the options if they want to. Thus, the options will be enforceable from year n+2 to year n+7. After that period, they will be considered as existing generators and will only have the opportunity to sell reliability options with one year duration. Also, if they choose to have a one year duration, they will not be allowed to ask for longer periods in the future.

1.4 The explicit penalty.

This is a high value that, in principle, may be set to twice the value of the strike price.

At the same time, this value discriminates between the old and inefficient plants and the new entrants (see [Vázquez *et al*. 02]). Considering this, but still in a very simple approach, the explicit penalty may be calculated as the fixed cost of a gas turbine (the new entrant with lowest investment costs) CF_{new} divided by the expected number of hours with prices above the strike price $h_{\rho>s}$ and also divided by the difference between the expected outage rate of the most inefficient unit that is acceptable in the system λ_{old} and the expected outage rate of a new gas turbine λ_{new}. $\dfrac{CF_{new}}{h_{\rho>s}\cdot(\lambda_{old}-\lambda_{new})}$

2 Then, the regulator should promote, through advertisement or other type of contacts, that a sufficient number of new players will attend the auction.

3 At the capacity auction, the generators will submit bids (each generator may submit several) expressing:

3.1 The amount of capacity in megawatts that will be committed by this bid.

3.2 The price required for this commitment.

3.3 For new generators, whether they want to have a five years duration of the option of just one year.

3.4 The physical unit that will be associated with the bid. We suggest to define this as production units (not power stations), except for imports where it is better to allow portfolio bidding (i.e., each foreign TSO may be considered as a single physical unit in this regard).

4 The market is cleared

4.1 First, a simple auction is conducted. The aggregated supply curve is constructed by adding up all of the bids in increasing price order and it is intersected with the amount of capacity that the regulator wants to buy. The last accepted bid sets the market price, and every bid with a lower price is provisionally accepted.

4.2 Transmission constraints are checked. If this solution respects them, then it is the final solution. Otherwise, a zonal auction is conducted, where the most expensive accepted bids in the congested end of the line are replaced by the cheapest rejected bids in the opposite end, until the constraint is satisfied. As a result, two different prices will appear, corresponding to the most expensive accepted bid in each area.

4.3 In any case, the amount of demand that the regulator wants to buy in flexibly increased to allow for bids to be accepted entirely. Bids of the same price are ordered according to their size, starting from the smallest. In the final solution, the quantity accepted is the minimum one that, being greater than the one defined in 1.2, includes only complete bids, considering the ordering abovementioned. This indivisibility condition will not apply for bids above a certain size —for instance, 500 MW—.

4.4 All of the accepted bids located within The Netherlands are awarded the capacity price in the Dutch node. All of the accepted bids located outside the country receive that price multiplied by some reduction factor —for instance, 0.7—.

5 The regulator must check the following series of conditions. If any of them is not satisfied, the corresponding bid should be rejected and the auction run again.

5.1 The sum of all the bids accepted for a certain physical generator have to be lower than its plate capacity

5.2 All accepted generators must show guarantees that cover their expected penalties (both the explicit penalty and the difference between the pool price and the strike price) for the year.

5.3 For new generators —i.e., units that are not already operative by the time the auction takes place— the requirement in 5.1 has to be checked against the projected capacity, not the real one. However, the guarantees in 5.2 should be higher since the credit risk is larger.

6 Immediately after the APX day-ahead market closes, each program responsible party submits

6.1 a balanced energy schedule, where energy production and interchanges with other parties are declared, and

6.2 a capacity schedule, where each party declares his obligations or rights associated to the payment of the implicit penalty. For generators, this includes their commitment resulting from the capacity auction and the obligations or rights sold or bought to other parties. For demands, this includes the rights derived from their actual consumption and the corresponding trading of obligations or rights.

7 For each hour during system operation at any moment during the horizon where the option is valid, and being ρ is the spot price and s is the strike price, and assuming that q_i represents the amount of reliability options sold by the program responsible party i, of which q_i^{ext} correspond to generators located outside The Netherlands, that $d_i^{scheduled}$ represents the demand declared by party i in the program submitted after the day-ahead market and $d_i^{real\ time}$ the demand actually consumed, that $g_i^{scheduled}$ is the production declared by party i in the energy program and $g_i^{real\ time}$ is the real-

time production, and that $R_{i,j}$ is the net amount of rights that party i has bought from party j, then:

7.1 Whenever $\rho > s$ and the flow through the interconnection is maximum, then the net obligation that party i has to pay for the reliability options is

$$(\rho - s)\cdot\left(q_i - \min\left\{d_i^{scheduled}, d_i^{real\,time}\right\} - \sum_j R_{i,j} - q_i^{ext}\right)$$

7.2 Whenever $\rho > s$ and the flow through the interconnection is not maximum, then the net obligation that party i has to pay for the reliability options is

$$(\rho - s)\cdot\left(q_i - \min\left\{d_i^{scheduled}, d_i^{real\,time}\right\} - \sum_j R_{i,j}\right)$$

7.3 Also, when the price at the day-ahead market exceeds the strike price and the flow through the interconnection is maximum, an explicit penalty for the generators is determined, only if it is positive

$$pen\cdot\left(q_i - \min\left\{g_i^{scheduled}, g_i^{real\,time}\right\} - q_i^{ext}\right)$$

7.4 Also, when the price at the day-ahead market exceeds the strike price and the flow through the interconnection is not maximum, an explicit penalty for the generators is determined, only if it is positive

$$pen\cdot\left(q_i - \min\left\{g_i^{scheduled}, g_i^{real\,time}\right\}\right)$$

7.5 Additionally, when the price at the day-ahead market does not exceed the strike price but the price for buying power from the balancing mechanism is higher than the strike price, then every party buying from the balancing mechanism is also charged the explicit penalty pen.

8 If player i includes some large consumer, and assuming that $q_{i,d}$ is the amount of options assigned by the regulator in 1.2 and that the previous $d_i^{scheduled}$ and $d_i^{real\ time}$ only corresponds to small customers —those that are completely hedged from the high prices— and that $d_{i,d}^{scheduled}$ and $d_{i,d}^{real\ time}$ are the equivalent values for the large consumers, then

8.1 Expression 7.1 is rewritten as

$$(\rho - s)\cdot\left(q_i - \min\left\{d_i^{scheduled}, d_i^{real\,time}\right\} - \sum_j R_{i,j} - q_i^{ext}\right) +$$
$$+(\rho - s)\cdot\left(-q_{i,d} + \max\left\{d_{i,d}^{scheduled}, d_{i,d}^{real\,time}\right\}\right)$$

8.2 And analogously for 7.2

8.3 Expression 7.3 is rewritten as

$$pen\cdot\left(q_i - \min\left\{g_i^{scheduled}, g_i^{real\,time}\right\} - q_i^{ext}\right) +$$
$$+pen\cdot\left(-q_{i,d} + \max\left\{d_{i,d}^{scheduled}, d_{i,d}^{real\,time}\right\}\right)$$

8.4 And analogously for 7.4

9 Finally,

9.1 The parties that sold some reliability options receives the premium fee that resulted from the auction in 4, and this payment is proportionally divided between all of the days in the binding period.

9.2 Consumers pay for that premium fees according to the amount of reliability options that they received (if large consumers) or according to their historical consumption (if small ones). For these latter ones some measure of coincidental peak demand could be used.

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