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REGULATORY COMMISSION
FOR ELECTRICITY AND GAS

STUDY

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on

'capacity remuneration mechanisms'

carried out in application of Articles 23, §2, second paragraph, of the Law of 29 April 1999 concerning the organisation of the electricity market

11 October 2012

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INTRODUCTION

The Belgian GAS AND ELECTRICITY REGULATION COMMISSION (CREG) has conducted this study to examine the generation capacity remuneration mechanisms implemented or under consideration in different countries and from which the Belgian electricity market can draw lessons.

The first chapter explains the general principles of capacity remuneration. The second chapter outlines the different types of mechanisms available and provides illustrative examples of their use in different countries. The third chapter looks at studies carried out by European countries planning to establish such a mechanism, while the fourth chapter looks at what can be learned from precedents in other countries. Considerations regarding implementation in the Belgian market are explored in the fifth chapter. The sixth chapter offers a conclusion.

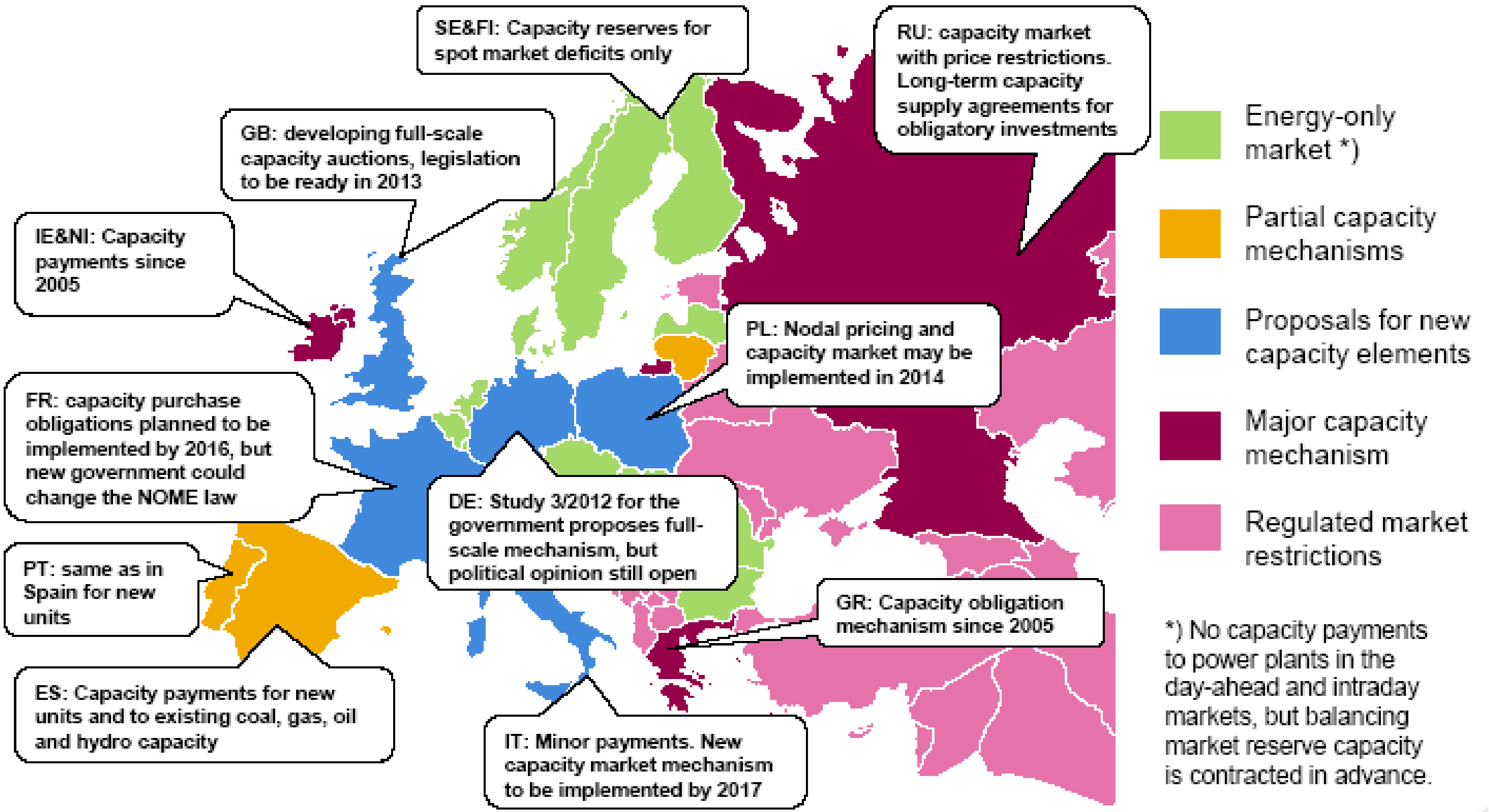
CREG's executive committee approved this study at its meeting on 11 October 2012.

I. GENERAL PRINCIPLES

As shown in the map on the following page, European countries can be grouped into two categories according to their chosen security of supply mechanism:

- *energy only markets*;
- *capacity mechanisms*.

Existing and planned capacity mechanisms in Europe



Source: Fortum

I.1 Energy only market[1]: Belgium, Germany, Netherlands, Great Britain, France, Texas, Australia, New Zealand

I.1.1 Principle

1. The generator is remunerated solely through selling energy in the market (remuneration for MWh). This assumes that the price signal sent by the market is sufficient to ensure future security of supply.

2. In theory, fixed costs are covered:

- by the infra-marginal rent for low and mid merit order units;

- by scarcity rent (when the market price is higher than the marginal cost) for peak units.

Increased occurrence of price spikes in the spot market gives the signal to investors that new investment in peak units (whose marginal cost is the highest) would be profitable. These market forces ensure that the system achieves the desired level of reliability.

⇨ **If the market functioned perfectly, income from the sale of MWh would be sufficient to ensure the profitability of the generation system.**

It is also worth noting the importance of price signals in the forward market, insofar as the majority of purchases and sales are made on a forward basis (protecting consumers from price spikes in the day ahead market).

[1] Joskow – Center for Energy and Environmental Policy Research: 'Competitive Electricity Markets and Investment in New Generating Capacity', April 2006

I.1.2 Limitations of the model

3. If the conditions are not met, such as in the following circumstances:

   i. market distortions (price caps that limit price spikes well below the value of lost load (VoLL)[2] and create a 'missing money' problem, subsidies, barriers to entry etc.);

   ii. low short-term price elasticity of demand;

   iii. low transmission capacity;

furthermore, if the market is experiencing a massive influx of subsidised renewable generation at low marginal cost, thereby disrupting the economic balance between baseload, mid and peak load generation, while also making spot prices more volatile and more extreme (downwards or upwards), investment in conventional technology appears more risky and less profitable (which is not necessarily the case with the generation portfolio).

⇨ **Additional measures and additional income in the form of capacity remuneration (CRM – Capacity Remuneration Mechanism) may be necessary** to avoid harming the investment climate and compromising the adequacy of generation technology, and therefore the long-term security of supply.

I.2 Adequacy

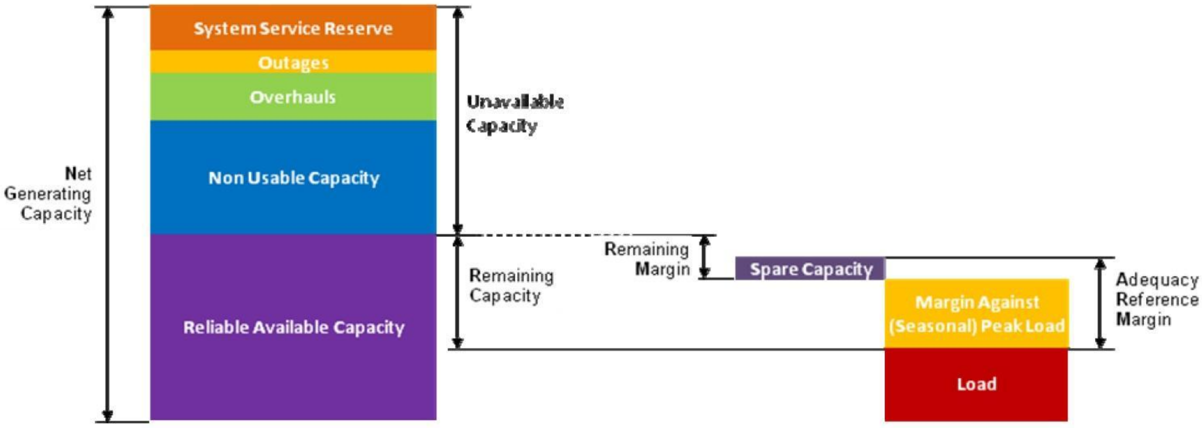
4. **Adequacy** can be defined as a system's capacity to satisfy total demand at all times. It differs from **security**, which is a system's capacity to cope with sudden disruptions (balancing and stability of the grid), to enable it to operate in real time.

[2] Maximum price consumers would be willing to pay for electricity to avoid a disruption in their supply. This price gives a signal regarding the adequate level of security of supply.

Adequacy therefore increases the likelihood of there always being enough generation available to match demand, but does not reduce the need for reserves in order to meet real-time demand. The following figure illustrates the method for calculating capacity reserve in relation to peak demand used by ENTSO-E[3].

It should be noted that adequacy is a prerequisite, but is not sufficient to guard against blackouts caused by an incident.

Figure 1: Sample analysis of the adequacy of a country's generation technologies



Source: ENTSO-E[4]

In this diagram, 'non usable capacity' refers to technology without an adequate degree of reliability. 'Load' takes into account demand side response capacity.

When the 'remaining margin' is negative, the system lacks generation capacity in normal operating conditions. When this is more than or equal to the 'adequacy reference margin', generation technologies are available for export. When it is less than the 'adequacy reference margin', the system must rely on imports in order to cope with difficult conditions.

[3] In its study No. 1074, CREG uses a slightly different methodology, based on simulating how the system operates. It uses a probabilistic method for calculating the availability of generating units, combined with technical and economic parameters and projected demand defined as an hourly chronological curve showing the evolution of energy demand during the year. The model iteratively and exogenously highlights the required investment in new generating units from the central system, while ensuring minimal costs as well as reliability (LOLE [loss of load expectation] of 16 hours per year for a non-import system).

[4] ENTSO-E Report, System Adequacy Forecast 2010-2025

I.3 Objectives of a capacity remuneration mechanism

5. The decision to set up a capacity remuneration mechanism can be based on different reasons:

- to ensure adequacy of capacity in a market with several stakeholders whose mission is no more to ensure the overall balancing of the system (cf. the USA in the 1970s);

- to solve the problem of 'missing money' (lack of capacity to cover fixed costs) as a result of a reduction in the number of operational hours of conventional generation units (mainly semi-peak) and the existence of spot market price ceilings[5];

- to manage intermittent RES (renewable energy sources) generation which benefits from a support policy (subsidising particular generation technologies, creating the need for subsidising other generation technologies);

- to manage a specific consumption pattern (for example consumption peaks in France).

The range of solutions implemented is dependent on the country's specific objective and context.

In short, a capacity mechanism requires evaluation of an appropriate level of capacity (e.g. 110% of peak demand) and an incentive to provide this reliable and flexible capacity. For generators, such an incentive takes the form of income for installed capacity, while for consumers it is remuneration for unused energy.

[5] In the Belgian market, these ceilings are 3,000 €/MWh in the day ahead market, and 9,000 €/MWh in the intraday market

II. TYPES OF CAPACITY REMUNERATION MECHANISMS (CRMs)

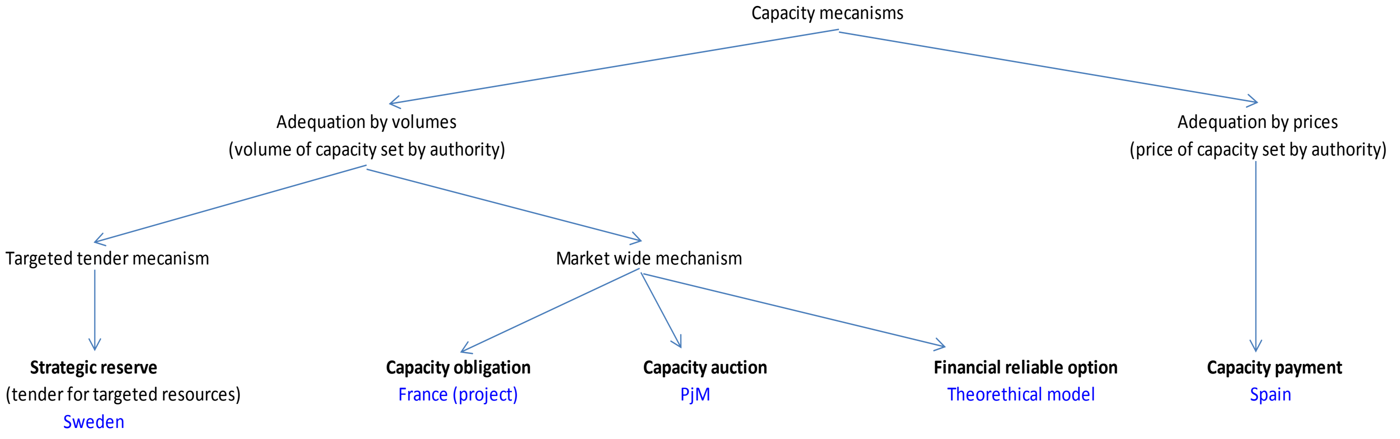
II.1 Types of CRM

6. CRMs fall into five categories[6]:

a) *capacity payment*;
b) *strategic reserve (tender for targeted resources)*;
c) *capacity obligation*;
d) *capacity auction*;
e) *reliability option*.

The diagram below illustrates the five mechanism types.

Diagram 1: Types of capacity remuneration mechanism



[6] DECC, Planning Our Electric Future: A White Paper for Secure, Affordable and Low-Carbon Electricity, July 2011
EURELECTRIC, RES Integration and Market design: are Capacity Remuneration Mechanisms needed to ensure generation adequacy?, May 2011

Security through prices

Remuneration is fixed, capacity quantities vary.

- **capacity payment**: a fixed amount, set by a central body, is paid to generators for available capacity and to provide an incentive to invest.

Security through volume

The amount of capacity is fixed, the mode of remuneration varies.

- **R4 strategic reserve (tender for targeted resources)**: capacity designed to ensure security of supply in exceptional circumstances is placed in reserve. The level of payment is set by invitation to tender (e.g. in Sweden).

Capacity market (juxtaposed to the commodity market)

- **capacity obligation**: suppliers are required to contract a certain level of capacity from generators at a price agreed between the parties, and to pay a fine if this capacity is not sufficient;

- **capacity auction**: the total required capacity is set several years in advance by the transmission system operator (TSO) or the regulator. The price is set by forward auction and paid to all participants in the auction. The cost is charged to the end customer through the suppliers, according to their off-take or off-take profile (e.g. PjM and ISO-NE markets in the USA);

- **reliability option**: this is also based on a forward auction, but for a financial instrument (call option) instead of a physical instrument enabling its bearer to cap its purchase price. If the spot price on the reference market exceeds a particular price (the strike price), the generator must be available if the system operator requires it, otherwise it must pay the difference between these two prices, which is refunded to consumers. The strike price therefore caps the energy market price at peak periods.

The amount of remuneration for availability paid to generators is determined by the options market. The penalty for non-availability corresponds to the option's strike price (this is a theoretical model only implemented in Colombia).

The mode of operation of the first four mechanisms is discussed in detail and illustrated below.

II.2 Security through prices mechanism

a) *Capacity payment*: Spain, Portugal, Ireland

How it works

7. In addition to remuneration received for selling MWh, certain types of peak units receive a premium, usually pre-set, for all or some of their available capacity. This capacity premium aims to encourage generators to invest. It is the regulator that sets the capacity price and the market that determines the amount of capacity.

There are different methods for calculating the premium. These generally take into account the likelihood of system failure (calculated based on the electricity S (supply) and D (demand)) and the cost of a disruption in the supply or the cost of investing in a new generating unit.

Examples:

Spain[7]

Context

Very competitive feed-in tariffs have been agreed for wind and solar energy, which has reduced the number of operational hours of CCGT plants. These ran for 3,920 hrs in 2008, 3,371 hrs in 2009, 2,715 hrs in 2010, and at only 30%-40% of their capacity in 2011, greatly reducing their profitability.

Solutions

1. Flat-rate remuneration for availability paid to all hydro, coal, gas and fuel-oil power plants available during pre-set peak periods (tariff periods 1 and 2), calculated using the following formula:

$RSD_{i,j} = a \times ind_j \times NP_i$

a = amount of annual payment: 5,150 €/MW in 2012 (reviewed annually)
ind_j = index multiplier (according to availability of the technology, based on historical data (coal: 0.912; combined cycle: 0.913; fuel-oil: 0.877; hydro: 0.237))
NP_i = net power of the available unit.

The maximum remuneration therefore varies between 4,640 €/MW/year and 1,220 €/MW/year and is intended to cover the fixed costs of the units remaining on standby in order to meet peak consumption and shortfalls in wind production.

It is the only remuneration paid to the current units.

Penalty: the remuneration is reduced in line with unavailable power and the number of hours of unavailability during peak periods.

[7] *Rapport de RTE au Ministre chargé de l'Industrie, de l'Energie et de l'Economie numérique sur la mise en place du mécanisme d'obligation de capacité prévu par la loi NOME* / RTE report to the Minister for Industry, Energy and the Digital Economy concerning the implementation of the capacity obligation mechanism under the NOME law, 1st October 2011

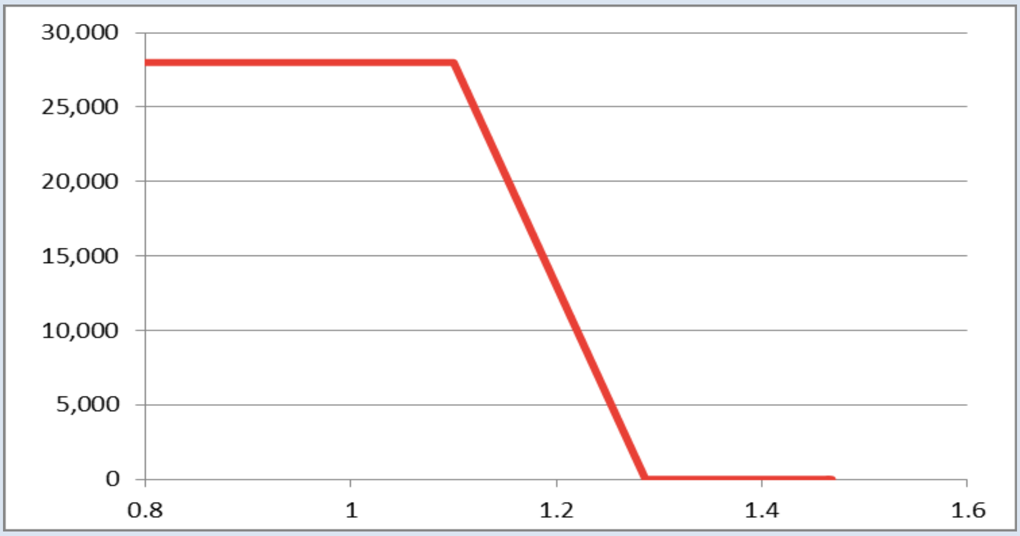
2. Investment aid for conventional generation facilities with a >50 MW capacity paid during the first 10 years, depending on the unit's availability at peak periods.

The amount of aid is calculated quarterly by the TSO, based on a **coverage ratio** defined as the ratio between total available power and the power consumed during peak periods. The aid is paid provided that, as an annual average, the power available during peak periods is greater than or equal to 90% of the facility's net power.

If the coverage ratio is ≤1.1 (10% reserve), the investment aid would be 28,000 €/MW/year (reduced to 23,400 € in 2012).

If the ratio is >1.1, the aid paid for additional MW would be reduced on a straight line basis, based on the following formula: ((193,000-150,000) x coverage ratio) €/MW/year. To reach 0, where the ratio is 1.29.

Figure 1: Capacity remuneration based on the level of reserve (€/MW)



For example, if the margin is 1.2, one 100 MW unit will receive:
(193,000 – 150,000) x 1.2 = 13,000 €/MW per year over 10 years, i.e. 13 million €.

The estimated cost of these measures for 2012 was 191 million (remuneration for availability) and 651 million € (investment aid) respectively. However, the government decided on 1st April 2012 to reduce the capacity payment by 10%.

Great Britain – former pool system discontinued in 2000

Principle

The market mechanism introduced in 1990 included remuneration for available capacity based on a formula that took into account loss of load probability (LOLP):

Capacity payment = LOLP[8] x (value of lost load – system marginal price)

Pool purchase price = system marginal price + capacity payment.

Problem

Whereas day ahead demand forecasts were known and generation by other market players was primarily baseload generation or, for IPPs (Independent Power Producers), linked to purchase contracts for take-or-pay fuel, the two main generators were able to assess the residual demand they needed to cover. This enabled them to manipulate the market by reducing their available capacity (by declaring the capacity unavailable during peak periods and by gradually reducing their generating capacity) in order to increase both the system marginal price and the capacity payment.

The New Electricity Trading Arrangements (NETA) introduced in 2001 scrapped capacity remuneration[9].

Pros and cons

8. The mechanism has the advantage of being simple, and allows for differentiated remuneration for existing and new investment. However, it has one major drawback: **remuneration is not based on market rules, creating a risk of pressure from investors to obtain higher aids that become the main driver for investment.**

[8] Loss of load probability

[9] CRI: Regulation Of The UK Electricity Industry, 2002 edition, University of Bath http://www.bath.ac.uk/management/cri/pubpdf/Industry_Briefs/Electricity_Gillian_Simmonds.pdf

II.3 Security through quantities mechanism

9. The required adequacy level is set in advance and stakeholders receive price signals in order to achieve this desired level of capacity.

There are two main types of mechanism: strategic capacity reserves and capacity markets.

II.3.1 Contract mechanism

b) Strategic capacity reserve (tender for targeted resources): Sweden, Finland

How it works

Quantity

10. Central bodies set, several years in advance, the amount of R4 strategic capacity reserve based on estimated demand and what the market would otherwise provide without the mechanism.

Price

11. At the end of a competitive tender process, the TSO contracts with providers of capacities (generation or DSR), entitling the TSO to deploy certain capacity. These will be withheld from the market (unless otherwise agreed) and will be the only capacity to receive remuneration. The R4 strategic reserve acts as generator of last resort.

The cost is passed on to suppliers, who in turn pass it on to their customers.

Example:

Sweden

Context

Peak demand is closely linked to temperature.
Available hydropower capacity varies from year to year, depending on water levels in reservoirs.

However, after liberalisation, producers began to close fuel-oil units previously used as backup, endangering security of supply. A temporary peak demand strategic reserve mechanism was introduced in 2003, initially for 5 years, and thereafter until 2020.

The reserve is used to meet peaks in demand during winter due to exceptional weather conditions.

Solution

The law entrusts the TSO with annually procuring a peak strategic reserve to be used between 16 November and 15 March. The TSO determines the quantity of the reserve (1,726 MW – i.e. 4.8% of net generating capacity – in 2012, of which 362 MW was demand response capacity). This volume cannot exceed 2,000 MW.

The TSO launches an annual competitive tender that is open to generators (the unit must be able to start up in under 12 hours) and to demand response capacity providers.

Initially, this capacity was withheld from the market. In January 2009, it was introduced into the day ahead market under specific conditions, so as not to influence market price formation:

- as a last resort after all commercial bids, if balancing cannot be achieved;

- at the price of the last accepted bid + 0.1 €/MWh. This is not ideal during severe scarcity periods, where small volumes can have a disproportionate effect on the price of electricity. To address this problem, assuming that demand response capacity providers participating in the reserve would be present even without remuneration, from 2012, they can also submit commercial offers in the day ahead market, with the aim of promoting the development of demand management.

If resources are not activated, they must be available to participate in balancing (after the commercial bids).

The cost per kWh following the tender process is relatively low for consumers and reserve capacity is not used every year.

The amount of the reserve will gradually decrease to 750 MW by winter 2017/2018 and the following winter, until the mechanism ends in 2020, and will contain a growing share of demand response capacity (from 2011). The aim is to return to an energy only market.

Finland uses the same mechanism. The contracts are for two years.

Pros and cons

12. The system is simple and quick to set up. It also causes minimal disruption to commodity market price formation (provided capacity is well organised and is only deployed in circumstances of exceptional peak demand). The market price remains the main driver for investment, and therefore does not solve the problems of price volatility and the risk of ‘missing money’.

This model is particularly suited to maintaining existing units with a view to exceptional use, **but is not ideal for attracting new investment.**

Moreover, if the required capacity is only available in limited quantities, the providers of that capacity have market power and could threaten to shut it down if they do not receive remuneration. A growing number of peak units are thus withheld from the market in order to be integrated into the reserve. This is simply transferring capacity. Indeed, if receiving a capacity payment becomes more attractive than remaining in the commodity market, this would lead to a lack of investment outside the mechanism, meaning that the TSO has to procure more and more generating capacity.

This mechanism is not ideal for remunerating the RES backup service, insofar as the units have to be used often. However, regular activation of the reserve, i.e. when prices do not reach significant peaks (in theory, the value of lost load) is not permitted. It would require larger capacity to be withheld from the market, some of which could otherwise be integrated in the merit order, influencing the increase in the price of electricity in the day ahead market.

II.3.2 Capacity market mechanisms

<u>How it works</u>

13. These are market mechanisms where generating volumes are determined several years in advance, in which the <u>supplier plays an active role,</u> together with penalties for failure to provide availability.

These mechanisms are based:

- firstly, on <u>suppliers' obligation</u> to provide <u>capacity guarantees</u> that match their customers' peak demand, together with a security margin, in order to balance overall supply and demand;

- secondly, on granting <u>capacity certificates to certified capacity providers</u> (of generation or demand response capacity);

- finally, on checks and <u>penalties</u> in the event that the capacity or the guarantee of capacity is unavailable (disincentivising the withholding of capacity in order to increase the price of electricity).

Suppliers can meet their obligations directly (self-supply/bilateral contracts) or indirectly (organised market, auctions).

To guarantee the remuneration of peak units through an auction mechanism, a given demand curve is plotted. There are two ways of doing this:

- the PjM method: the generator can make a margin on variable costs in the energy market and the given demand curve is designed so that they can recover the missing value to cover fixed costs (missing money) in the capacity market (which goes against price formation in a liberalised market);

- the peak energy rent method (ISO-NE): the capacity market pays all fixed costs of the peak unit (full cost of the capital). A price cap is set in the energy market. Any margin made above the variable cost is deducted from income earned by the generator in the capacity market.

Whichever method is used, to prevent unjustified remuneration for capacity, a mechanism for controlling income must be implemented.

Capacity certification is a key feature of the mechanism. To participate in the market, capacity must meet certain criteria (length of availability, minimum power available etc.) to guarantee adequacy.

Various market models are possible, depending on the degree of centralisation, the time horizon and the scope of the mechanism.

c) Capacity obligation (decentralised approach) (French proposal)

How it works

14. Each supplier evaluates their own capacity needs, based on the forecast consumption profile of their customer portfolio (bottom-up approach).

It is then up to them to meet their obligations, either by certifying their own generation technology, or by signing bilateral contracts to purchase capacity credits from capacity providers.

The supplier must pay a penalty if they have not contracted enough capacity.

France (proposal)

Specific context

15. Peak demand is growing continually, and much faster than average consumption (large electrical appliances used for heating, in particular, induce high thermal sensitivity and record peaks in demand in winter).
Consequently, in a context where there is uncertainty regarding the profitability of investment in advanced generation technology, security of supply is endangered.

Objectives

Two goals are pursued:

- to improve peak demand management, such as by developing demand response provision;
- for all suppliers to bear the cost of covering peaks, rather than solely EdF.

16. The NOME law introduced a capacity obligation on suppliers. It requires that, by 2015, each supplier give a guarantee that they will directly or indirectly provide the generation or demand response capacity to meet their customers' demand during consumption peaks.

The government has appointed RTE to analyse the implementation of a capacity mechanism. On 13 October 2011, RTE published a report in which it recommended the creation of a capacity market.

A bill 'on the introduction of a capacity mechanism in the electricity sector' is under consideration.

Solution under consideration[10]

17. The capacity mechanism relies on two central components:

- mandatory signature by operators of generation and demand response capacity, of a certification contract with RTE for all their capacity, committing them to a certain level of availability and, depending on this level, assigning them a quantity of capacity guarantees (transferable and tradable certificates). A contractual financial penalty is provided for in the event of failure to fulfil their obligations;

- the obligation, established 4 years in advance, for each supplier to hold, each year, capacity guarantees calculated based on their customers' consumption[11] and a margin rate. Suppliers acquire capacity guarantees in order to fulfil their obligation. They are subject to an administrative penalty imposed by the CRE if they breach their obligation.

A balancing measure is also provided for. If there is a very high risk of imbalance, the Minister for Energy may launch a call for projects, the cost of which will be shared between suppliers in proportion to their capacity obligation.

18. The capacity obligation creates a supply side 'demand' for capacity guarantees. Certification of generation and demand reduction capacity creates a 'supply' of capacity guarantees. This supply and this demand constitute a market. This market is for power and is independent of the wholesale electricity market, which is for energy. Capacity guarantees relate to guaranteed available power, regardless of whether there is actual generation.

[10] French competition authority, Opinion No. 12-A-09 concerning a bill on the introduction of a capacity mechanism in the electricity sector, 12 April 2012.

[11] The reference consumption of their customer portfolio = (consumption during peak periods with baseload temperatures – demand response contracts)

Penalty

19. Capacity operators appoint a certification official who is responsible for penalties arising from any discrepancy subsequently found between the capacity guarantee and actual availability.

RTE then calculates the reference consumption of each supplier and gives notice of the capacity obligation. If the supplier does not hold the sufficient number of capacity guarantees, they are subject to a financial penalty. If the supplier holds too many capacity guarantees, they are obliged to offer them for sale.

Pros and cons

20. This mechanism limits the need for regulation. It places responsibility for adequacy of capacity in the hands of the suppliers. The TSO merely sets the reserve margin that each supplier must have. The signal for investors is therefore less clear than in the centralised approach.

Determining volume is based entirely on suppliers' forecasts, although they do not have long-term visibility of their portfolio. They therefore risk favouring short-term solutions, which results in more volatile prices for customers and a lack of a long-term price signal for investors.

Moreover, this mechanism can create a barrier to entry for new suppliers, since they have to satisfy relatively unknown demand, but offers an advantage for suppliers linked to generators.

Finally, it may deter suppliers from contracting with customers with more peak demand presence.

d) Capacity auction (centralised approach) (Pennsylvania market – New Jersey, Maryland (PjM reliability pricing model (RPM)), ISO-NE, USA, UK proposal)

Goal

The forward capacity market is designed to open up the opportunity for generation, demand, energy efficiency and the transmission network to provide solutions for generation technology adequacy.

Example:

PjM

Capacity quantity and obligation

21. The network operator sets the installed capacity need 3 years in advance, based on a peak demand forecast, together with a reserve margin (top-down approach reminiscent of the multi-year investment schedule). The reliability criterion is based on a major incident occurring every 10 years.

It then assigns capacity obligations to each electricity supplier according to their customers' participation in consumption peaks.

The supplier can fulfil their obligations in different ways:

- by building their own generating plants or by contracting them bilaterally;
- by using the capacity contracted by the TSO through auctions;
- by signing bilateral contracts.

Market

22. Demand is determined by the capacity obligation imposed on all electricity suppliers.

The supply of capacity may come from existing generating plants (mandatory participation), including those with intermittent generation (i.e. which cannot guarantee 12 consecutive generating hours), and future plants, from existing and future demand response capacity, from increases in transmission capacity, and from generating units located outside the PjM zone, provided they can demonstrate having the necessary transmission capacity and that they are certified. Market participation is mandatory (capacity reserved for export and already contracted by suppliers, or which does not meet certain criteria, e.g. environmental criteria, is exempt).

The supply relates to flexible capacity sources. There is another type of contract for the provision of non-flexible capacity.

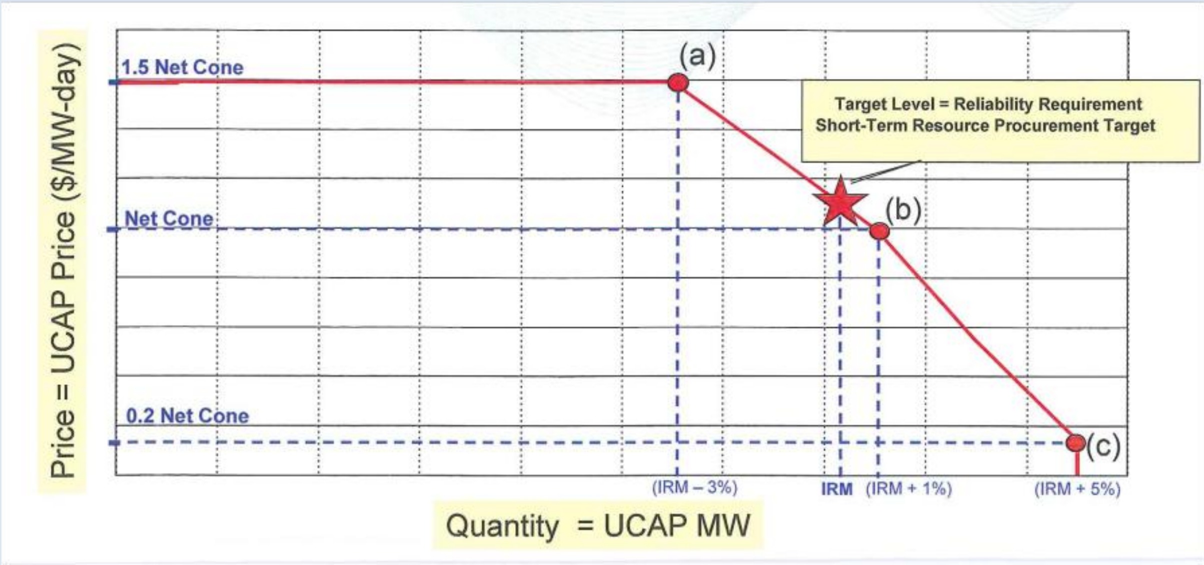
The capacity actually available in peak summer (unforced capacity – UCAP) is determined based on installed capacity and the likelihood of system failure.

23. A mechanism for auctioning capacity certificates with a single buyer (TSO) was introduced in 2007.

A first auction three years before the commitment period (to allow competition between new and existing units), and up to 3 additional auctions close to the commitment year (23 months, 13 months and 4 months before delivery), are held to address any inaccuracies in the initial projections of supply and demand and to achieve the total capacity required.

To reduce price volatility, a sliding demand curve is plotted based on Net CONE (Cost of New Entry) and the target quantity. The demand curve is plotted in such a way that the price of capacity equals Net CONE for the target quantity +1%. For quantities less than the target quantity -3%, the capacity price is set at 150% of Net CONE. It then decreases on a straight-line basis (reflecting the decreasing value of increased reliability provided by capacity that exceeds the required quantity) and falls to zero when the quantity offered exceeds the target quantity of 5%.

Figure 1: Example of capacity demand curve.



Source: PjM

Point B represents the desired level of capacity reserve.

Net CONE (net cost of new entry) = gross CONE – Energy and ancillary services offset.

Gross CONE = the estimated cost of developing one reference combined cycle gas turbine (CCGT) that a new entrant needs to cover. This includes the capital and fixed operating costs required to build and operate the generating unit *(levelised (to obtain an annual cost) capital cost + annual fixed O&M).*

CONE is set administratively based on experts' advice. It is indexed annually and its parameters are reviewed every 3 years.

Energy and ancillary services offset = the estimated net profit that this new entrant will make from selling electricity and ancillary services, obtained by calculating the 3-year average of income achieved from one leading technology unit. This is the margin on variable costs.

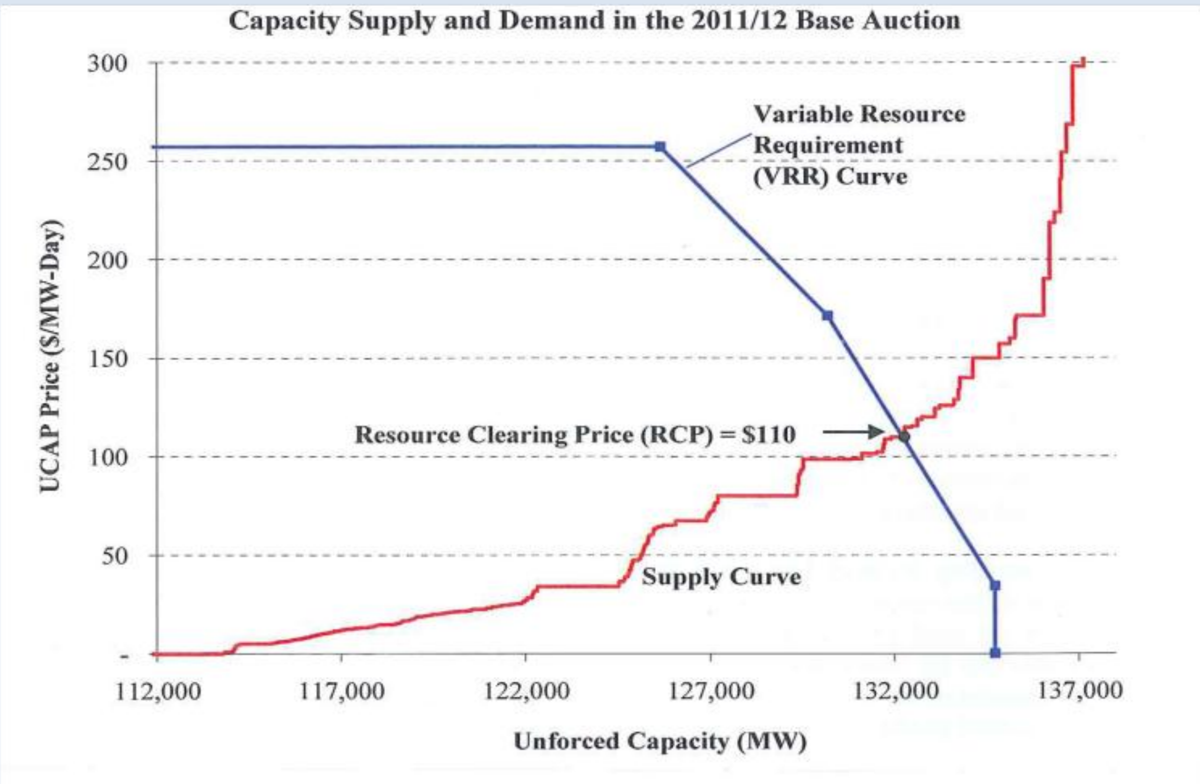
Net CONE therefore represents the residual annual remuneration (missing money) the new entrant must obtain in the capacity market to cover the fixed costs of the generating unit.

The supply curve is plotted based on the position of the capacity offerers.

The auction starts at a price representing twice the net CONE. Offerers (of previously-certified capacities) indicate the quantity they are willing to supply at that price. If supply exceeds demand, the price decreases. The process repeats until supply matches demand. The clearing price is paid to all successful capacity bidders.

If the supply of available capacity is to the left of point B, the demand curve is designed to produce a price that encourages new generation capacity to be built. However, if the capacity offered exceeds demand, income decreases, which can lead to capacity being withheld if it is unable to generate additional income by selling energy.

Figure 2: Capacity supply and demand curves



24. After the auction, the TSO signs a contract with the providers of generation or demand response capacity, entitling the TSO to deploy their capacity.

25. A bilateral contract enables generators to hedge the risks associated with their commitments and suppliers to hedge the risk associated with the cost of capacity.

26. Checks are then performed to verify actual availability of peak capacity (verifying generation includes checks on overall availability during the year, peak availability, actual installed capacity and planned outages. Checks on demand response involve verifying power reduced per customer, and checks on demand response capacity).

27. Income may be partially or fully cancelled out by penalties. Two penalties may be imposed; one is based on the general availability of capacity over the whole year, while the other penalises non-availability during peak periods.

Supplier's obligation

The supplier knows their daily capacity obligation 36 hours in advance.

Covering costs

28. The contract costs are shared between suppliers in proportion to their customers' contribution at peak periods (daily capacity obligation x capacity price). They then pass on this cost to their end customers.

Variants

29. Other market designs exist. PjM allows a margin to be made on variable costs and offsets missing money. ISO NE prevents a margin being made on variable costs in the energy market and pays all fixed costs in the capacity market.

Additional rules have been added in some markets (capping offer prices for existing capacity, multi-year price guarantee, capacity needs differentiated by type etc.), so that the price signal achieves the objective of generation technology adequacy.

Pros and cons

30. **Penalties for non-availability are an obstacle to strategically withholding capacity in an energy only market.**

31. In a market with a single buyer, the supplier finances the measure but does not participate in the market.

32. It is a complex and expensive mechanism to implement. The administrative costs associated with setting up and monitoring such a market are additional costs to be covered

by the customers. This complexity and cost can be a barrier to entry for small-scale generators and suppliers. They are also an obstacle to system downtime.

33. The market must be accessible for alternative modes, such as storage. However, storage is difficult to incorporate because its cost is rarely competitive compared with new generation technologies.

34. In theory, the cost of capacity is partially offset by scarcity rent disappearing from the energy market. In practice, firstly, price caps imposed in the energy market already protect consumers from excessive price spikes, and secondly, the interaction between the two markets is not conducive to transparency.

35. A poor design of the capacity market could lead to excessive remuneration of capacity, while poor assessment of needs may lead to overcapacity, resulting in an increase in costs charged to customers. Undercapacity may have the same result, therefore failing to guarantee generation technology adequacy.

36. There is also a high risk that some stakeholders would be in a position to influence the market. By withholding capacity from the market, they would be able to drive up the price of capacity (this problem is only partially resolved by plotting a descending demand curve).

37. The annual auction mechanism does not really provide long-term visibility.

III. EUROPEAN COUNTRIES CURRENTLY CONSIDERING A NEW MECHANISM

III.1 France[12]

38. The proposed mechanism is described in paragraphs 15-20 above. It would come into effect in winter 2016-2017 at the earliest. Therefore, to meet specific needs identified for winter 2015-2016, a call for proposals for new electricity capacity would in theory be launched in mid-2012.

39. In its opinion on the draft decree, the CRE draws attention to the following points[13]:

- *'In the short term, the demand between supply and demand in the French electricity system does not appear to be threatened. The implementation of a capacity mechanism may, however, be justified in the long term, given the structural trend of increasing peak demand.*

- *The capacity obligation mechanism is intended to improve the remuneration of peak technologies and of demand response resources in particular.*

- *The introduction of a capacity mechanism in France is likely to cause electricity retail prices to rise.*

- *The CRE will ensure that the capacity mechanism has no adverse effect on competition.*

- *A capacity obligation mechanism remains a complex tool to implement, with potentially significant effects on how markets function.*

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[12] Rapport de RTE au Ministre chargé de l'Industrie, de l'Energie et de l'Economie numérique sur la mise en place du mécanisme d'obligation de capacité prévu par la loi NOME / RTE report to the Minister for Industry, Energy and the Digital Economy concerning the implementation of the capacity obligation mechanism under the NOME law, 1st October 2011 http://www.developpement-durable.gouv.fr/IMG/pdf/Rapport_Mecanisme_de_capacite_light.pdf

[13] CRE decision of 29 March 2012 Capacity mechanism - Opinion - Rulings - Documents - CRE

- *Careful introduction of this mechanism into the integrated market will require coordinated effort at European level.*

- *Legislative changes will be essential to ensuring the mechanism functions well.'*

40. The French competition authority, in its Opinion No. 12-A-09 of 12 April 2012 regarding the draft decree, also expressed serious concerns about the introduction of such a mechanism. It believes that such a measure would increase the complexity of the regulatory framework and generate additional costs to consumers (which the CRE estimates at 200-500 million € per year), and that there was no evidence that it was needed:

a) to encourage investment: firstly, there is no consensus regarding the 'missing money' theory and secondly, there are other reasons that discourage alternative suppliers from investing in generating technologies, such as insufficient access to baseload electricity under the same conditions as EdF and the way regulated tariffs are set;

b) to manage demand during intense peak periods. The competition authority believes there are cheaper methods, such as, for individuals, phasing out electrical heating and improving insulation and, for businesses, transmission tariff differentiation between peak and off-peak hours.

Latest developments

41. The new administration has reopened the debate on energy transition. The NOME law provisions could be halted and replaced by measures such the introduction of stepped tariffs for gas and electricity. **The proposed creation of a capacity market may be abandoned due to its potential impact on the price of electricity and on intensifying the speculative nature of the market.**

III.2 Germany

Context

42. EnergieKonzept 2050 proposes examining the need for additional reserves and the establishment of a capacity market.

Generation capacity is not a medium-term problem in Germany. There are congestion problems in the transmission network between the north (where renewable generation is concentrated) and the south (where the majority of large industries are based). This endangers security of supply in the south of the country, since the closure of nuclear plants and the announcement by the municipal authorities and utility companies of their intention to close some of their power plants, mainly gas, that are deemed unprofitable. A plan to expand the transmission network is expected to address regional imbalances between supply and demand. Pending its completion, a capacity reserve would be established to handle congestion problems.

According to the BDEW confederation (comprising water and energy utility companies), 84 plant projects of over 20 MW, totalling 42 GW and representing a total investment of 60 billion €, are planned. 69 of these projects (36 GW) have at least passed the permission application stage. However, some gas power plant projects are on hold due to uncertainties associated with their number of operational hours.

In a May 2012, a BundesNetzAgentur (federal network agency) report also noted that since liberalisation, 15 GW of new capacity had been built despite overcapacity, primarily CCGT units since 2007, without the need for any subsidisation.

Capacity market

43. The German Government estimates that by 2020, 10 GW of new thermal generation capacity will be needed, in addition to the units under construction in order to ensure nuclear

energy phase-out and the transition to a larger share of renewable energy in the energy mix. **It remains, however, very reticent regarding the introduction of a capacity market[14].**

The main utility companies, RWE and E.on, are hesitant about the idea of a capacity market, believing that such a mechanism is not necessary for several years yet, and that the initiative should be left to businesses.

Reserve

44. In a May 2012 report, BundesNetzAgentur (BNetzA), the regulator, stated that legislative measures should be taken to prevent the closure of conventional generation units, otherwise, in southern Germany, the need for reserve units will increase exponentially. Unprofitable units likely to be integrated into the reserve have been identified in Germany and in Austria. Discussions are currently focused on the financing method. **The Minister for the Economy believes that generators should be responsible for supplying the reserve, with no financial compensation.** Generators believe that they should be compensated for all their costs.

It is expected that the reserve units will be made fully available to the TSO.

BNetzA has estimated the amount of the capacity reserve for next winter at 2,600 MW (including 1,075 MW in Austria). This capacity reserve will be used for redispatch if technical difficulties occur in the South of Germany. If necessary, reserve capacity can be used as a strategic reserve.

In a study conducted in June 2012, Ecofys estimates the cost of a 4 GW reserve at between 140 and 240 million € per year, which would generate a price increase for the end customer of 0.1 cents per kWh.

[14] Argus Media, 23 April 2012

III.3 Great Britain

Context

45. As part of a major reform of its energy market designed to reduce emissions, and to address the expected loss of a fifth of its existing capacity, the UK Department of Energy and Climate Change (DECC) announced on 15 December 2011 its decision to set up a legal framework to establish a capacity market in 2014.

Until now, the country had a comfortable reserve of CCGT units as a result of the ‘dash for gas’ of the 1990s. Intermittent (wind) or less flexible generating units (nuclear) are set to replace them. The CCGT units will therefore operate less and less and more sporadically, making their profitability more precarious. However, the intermittent or inflexible nature of these new units makes the existence of peak thermal units and other non-production approaches more essential (i.e. demand side response and storage).

Objective

46. The government aims to provide a plan of action in the event of lack of capacity (the intermediate scenario indicates that this should not occur before 2020).

47. The system will only be used if necessary and if it proves cost effective (compromise between the reliability of the system, based on a pre-defined criterion, and the cost to the public). The first auction could take place in autumn 2014, for winter 2018-2019 availability.

How it works

48. The option chosen is the **capacity auction (cf. PjM)** capacity market[15]. The capacity reserve solution was ruled out.

49. Peak demand will be forecast by the TSO (National Grid), Ofgem, and by other experts, and will be provided to the government.

50. The government will decide the total amount of capacity required to ensure security of supply (peak + margin). This amount will be contracted through a competitive central auction run by the TSO. Demand side response and storage can participate in the auction. The auction will take place 4-5 years ahead of the delivery year in which providers are required to make the capacity available, to allow both existing and new providers to participate, which will promote liquidity and competition in the market (the lead time could be shortened for the first auction).

51. Insofar as the subsidies received by RES are sufficient to support investment, they will be excluded from the capacity market.

52. To prevent current investment projects from being postponed until the introduction of the capacity market, units built between 2012 and the first auction will be treated in the same way as the new capacity.

53. Capacity providers who are successful in the auction will enter into a capacity agreement. During the year(s) specified in these agreements, they will receive a predictable revenue stream to cover the costs of their capacity. In return, they commit to providing electricity when needed or face penalties.

[15] DECC, Electricity market reform: capacity market – design and implementation update, 28 March 2012

Costs

54. In its impact assessment[16], the DECC estimates the net present value of a capacity market at around £-2,613 million over the 2012-2030 period, as compared with an energy only market functioning in optimal conditions. Additional costs are treated as insurance paid by consumers against price spikes and blackouts.

55. The costs of capacity will be shared between electricity suppliers in the delivery year, for example, based on their peak load, to encourage them to reduce their share of peak load. Penalty payments will be returned to suppliers.

The final design of the market should be known in late 2013. Some aspects of the system have yet to be examined:

Interaction with balancing services

56. The capacity market does not seek to contract for flexibility, but to ensure an adequate volume of total capacity. DECC is counting on the electricity market to send adequate price signals to bring about the right mix of flexibility to ensure the system remains in balance. The design of the capacity market will take into account its interaction with the procurement of balancing services.

Type of auction

57. The auction must guarantee that the revenue is sufficient to incentivise capacity agreement holders to participate, and also that consumers will not be paying more than is necessary to ensure security of supply. Different design options are being considered, for example ‘pay as bid’ and ‘descending clock’ approaches. Whether existing and new providers should be treated in the same way will partially determine the type of auction.

[16] DECC, Impact Assessment, 15/12/2011

Duration of capacity agreements

58. The duration of the capacity and whether existing and new providers should be treated differently have not yet been decided:

- firstly, short-term, uniform contracts (1 year, for example) are more easily tradable, and consumers are not tied into long-term contracts;

- on the other hand, longer contracts mean that costs can be spread over a longer period, potentially reducing the cost of capital for new investments and avoiding ‘boom and bust’ cycles. The option chosen will probably be to contract for 1 year for existing capacity, and for longer periods for new or refurbished capacity (for example, to guarantee coverage of fixed costs over 5 years).

Pre-qualification requirements

59. Capacity providers must satisfy certain criteria before they can participate in the auction. They should demonstrate that their capacity will be in place in the delivery year, in order to mitigate the risk of awarding contracts to providers who are subsequently unable to provide capacity when needed.

60. Specific criteria will be developed for GB-based generation, for interconnected capacity and for non-generation technologies such as demand side response (DSR) and storage.

If it is desirable to include non-generation technologies in the auction, a series of questions arise about the baseline to take into consideration for verification.

Secondary auctions and trading

61. It is possible that a secondary auction closer to the delivery date will be organised to correct shortfalls in supply projects.

62. The intention is to introduce a secondary market for capacity agreements in order to allow contract holders to manage their exposure to risk by reducing or augmenting their obligations.

Supply and penalty regime

The approach for the penalty model may be administrative or market-based.

63. With the administrative approach, fixed rules define the type and size of penalty. This has the advantage of being predictable, but has the drawback of requiring more rules (volume to be offered by each provider, periods in which the provider would need to be available) and requires physical checking.

64. A market-based penalty model could take the form of ‘reliability option’. The capacity agreement commits the holder to pay back the difference between the price of electricity in a reference market and a pre-set price in that market (the strike price). The strike price would be set at a level between normal market conditions and scarcity (e.g. £500/MWh) in order to limit the extent to which the capacity market interferes with the electricity market. This means that holders of capacity agreements have a strong incentive to be available in scarcity periods, and that in return for paying for capacity, consumers are protected from market prices going above the strike price.

This approach avoids administrative checks but offers less assurance, since no checks would be made to ensure that capacity providers have sufficient capacity.

It may also have a greater impact on liquidity in the forward market, as capacity providers may seek to hedge the risk they are exposed to in the capacity market by selling electricity in the reference market.

65. In analysing the potential conflicts of interest and synergies arising from the key role assigned to the TSO in implementing the mechanism, DECC highlights that this would further increase the complexity of the TSO's role and the electricity sector's dependence on their performance in this role.

III.4 Italy

66. In 2004, a provisional capacity remuneration system was implemented during a period of scarcity of generation resources.

Eligible plants (selected based on their reliability) receive:

- basic remuneration determined in advance, based on forecasts of supply and demand for each hour of the following day;

- further payment if the weighted average price on the IPEX stock exchange is less than 20% of the regulated price and if the plant is located in an area with low prices (Enel, for example, does not receive this additional payment).

These units must be available in the day ahead market during peak periods, as well as on certain critical days of the year.

Remuneration is determined in advance on the basis of supply and demand forecasts, rather than on actual data.

The measure is funded by a 0.5 €/MWh levy.

In 2011, during a period of overcapacity, the regulator proposed a new system to be introduced in 2017. This proposes that each producer offering backup capacity is remunerated per MW on the basis of a market mechanism. The incentive tariff would be paid by the TSO, who buys options on the generation capacity deemed necessary for a 4-7 year horizon. The first auctions were due to take place in 2012, so as to allow five years for investors to build the generation units.

III.5 Spain

67. Due to the economic crisis, the new government wants to reduce the cost of capacity remuneration. In late May 2012, the regulator, CNE, launched a consultation process in order to establish a new mechanism.

68. The new mechanism could be based on the reserve market, which started in May 2012. The electrical company REE (*Red Eléctrica Corporación*) publishes a forecast of demand for the following day, every day at 2pm. Generators then have 30 minutes to publish their reserve capacity offers for the following day (for hours treated as critical). The lowest offers are accepted. REE publishes the marginal price for each hourly slot expressed in €/MW. If the pool calls up the reserve, the generators receive the pool price, plus a premium for availability.

III.6 Netherlands

69. The August 2003 heatwave generated an increase in demand, but also reduced generation due to the limited availability of cooling water. This has resulted in price spikes in the market and, in 2004, led to a debate about introducing a capacity market. A *Strategisch Reserve Model* was set up, but has never been used. Monitoring of generation technologies was initially introduced. This concluded that security of supply had improved and that there was therefore no need to activate the reserve mechanism.

IV. LESSONS FROM FOREIGN EXAMPLES

IV.1 Mixed results

70. Although a number of countries have adopted or plan to adopt a capacity remuneration mechanism, this trend must be viewed with caution.

US PjM	The mechanism had to be modified several times before producing results.
Spain	In 2012, capacity payments were reduced by 10% (to help reduce the tariff shortfall).
France	Negative opinions from the CRE and the competition authority. NOME law called into question by the new government.
Germany	No political consensus for establishing a capacity market. The formation of an R4 strategic reserve is being considered.
Netherlands	Opted for an R4 strategic reserve, but did not consider it necessary to implement it.
UK	Discontinued the first mechanism it set up. Great caution in developing a new mechanism, which will be used only as a last resort.
Sweden	Aims to phase out the system in 2020, to return to an energy only market.
Italy	Reviewing their current system.

IV.2 Regulatory uncertainty

71. None of these mechanisms can 100% guarantee security of supply.

However, some are very complex, time consuming to implement and generate increased costs to the consumer, while also creating regulatory uncertainty associated with potential adjustments and their duration.

V. IMPLEMENTATION IN THE BELGIAN MARKET

72. The Belgian generation system faces the challenge of integrating growing intermittent renewable generation, together with an ageing generation system. Although the measures currently proposed by the government, which include rescheduling the phasing out of nuclear power, may ensure the adequacy of generation technologies in the medium term, the real challenge is to ensure adequacy in the longer term, while meeting environmental targets agreed at European level for renewable generation and reductions in greenhouse gas emissions, and bringing electricity prices under control.

73. In its current structure, the market has difficulty reconciling these three targets: adequacy, environment and price. Therefore, support measures to facilitate the transition need to be considered. These are restricted by the legal framework.

V.1 Legislation

74. Article 5 of Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006 concerning measures to safeguard security of electricity supply and infrastructure investment provides that measures should be taken by Member States to maintain a balance between supply and demand:

> *‘1. Member States shall take appropriate measures to maintain a balance between the demand for electricity and the availability of generation capacity.*
> *In particular, Member States shall:*
>
> > *(a) without prejudice to the particular requirements of small isolated systems, encourage the establishment of a wholesale market framework that provides suitable price signals for generation and consumption;*

(b) require transmission system operators to ensure that an appropriate level of generation reserve capacity is available for balancing purposes and/or to adopt equivalent market based measures.

2. Without prejudice to Articles 87 and 88 of the Treaty, Member States may also take additional measures, including but not limited to the following:

(a) provisions facilitating new generation capacity and the entry of new generation companies to the market;

(b) removal of barriers that prevent the use of interruptible contracts;

(c) removal of barriers that prevent the conclusion of contracts of varying lengths for both producers and customers;

(d) encouragement of the adoption of real-time demand management technologies such as advanced metering systems;

(e) encouragement of energy conservation measures;

(f) tendering procedures or any procedure equivalent in terms of transparency and non-discrimination in accordance with Article 7(1) of Directive 2003/54/EC.

3. Member States shall publish the measures to be taken pursuant to this Article and shall ensure the widest possible dissemination thereof.'

75. Article 5 § 4 of the Electricity Act of 29 April 1999, as amended by the law of 8 January 2012 (reprinted in full in Appendix 1) provides for a remuneration mechanism for the construction of generation facilities, and that end customers shall bear the cost of such a measure through a public service obligation. The practicalities of implementation are yet to be defined (since 2002).

76. This legislation provides for the formation of a reserve and the tendering procedure adopted in the plan proposed by the Belgian energy minister on 27 June 2012[17] (hereinafter: Wathelet plan).

V.2 Implementation methods

77. It is worth drawing attention to the potential for disruption of the energy market that may be caused by a capacity remuneration mechanism:

- if its design is flawed, creating a capacity market alongside the energy market may cause harmful interferences between these two markets and disrupt the price signal in the commodity market. The costs of the system may therefore exceed the benefits;

- it creates an obstacle to market integration and distorts competition between neighbouring countries if its implementation is not coordinated at European level.

The priority should therefore be given to improving the functioning of the intraday, spot and forward markets at European level.

V.2.1 Formation of an R4 strategic reserve

From this perspective, of all the models presented in the previous chapters, the R4 strategic reserve mechanism is:

- relatively quick and easy to set up;

- the mechanism that causes least disruption to the energy market, provided capacity is evenly spread and is only used in special circumstances.

[17] *Le système électrique belge à la croisée des chemins : une nouvelle politique énergétique pour réussir la transition* (The Belgian electricity system at a crossroads: a new energy policy for a successful transition), 27 June 2012.

It does, however, provide only a partial solution to the problem and is not without risk:

It might not encourage the development of new flexible plants

- if the mechanism is implemented one year from now, it overcomes the problem of scarcity identified for the following year. It provides an incentive for less efficient existing plants to remain in the system for one further year. **It will therefore help to extend the life cycle of the least efficient units at the expense of new, more efficient units;**

- to avoid too many threats of closures, the Wathelet plan proposes, as an initial step, placing the unit for auction. Technically speaking, taking over an unknown unit at the end of its useful life poses great risks, which would result in higher operating costs for the buyer. It is therefore unlikely that such a strategy would succeed unless it is combined with an investment outlook. The true value of a unit at the end of its useful life in fact lies in its operating site. The two proposed measures could therefore be combined: placing units in reserve should only be temporary and accompanied by an investment plan (subsidised or non-subsidised), otherwise extending the life of existing units will immobilise generation sites and create a further obstacle to investment.

If poorly designed, it could disrupt the functioning of the commodity market

- unlike primary, secondary and tertiary reserves, if the R4 strategic reserve is introduced in the day ahead market, it may compete with other generation or DSR capacity. In the day ahead market for supply (at a set price), the measure amounts to a price cap in the commodity market. If this is too low, it reduces the price of electricity during peak periods and thus the incentive to invest in peak units. In fact, the lower the strike price, the lower the scarcity rent from other generating units. This would encourage the closure of additional units, which would in turn necessitate their integration into the reserve to maintain the desired level of capacity (slippery slope). An increasing number of units will then no longer be managed by the market mechanism, but remunerated and administered by the administrator of the reserve. This will result in simply shifting the market's capacity to the reserve;

- similarly, if receiving a capacity payment becomes more attractive than remaining in the commodity market, this would lead to a lack of investment outside the mechanism, meaning that the size of the reserve should gradually increase.

Its cost could increase if market power is exercised

- the reserve could be formed through a tender process. In this instance, if the required capacity is only available in limited quantities, the providers will have market power which they can exercise.

  The government's preferred option involves a negotiated approach after which the CREG should decide on the level of remuneration paid to the unit placed in reserve. It would consist of fixed costs that are strictly dependent on it remaining active, less the difference between the pre-set activation price and the marginal price of actual activation (revenue from the commodity and balancing markets), to which a fair margin would be added. This process also poses risks of excessive remuneration. Asymmetry of information between the generator and the regulator will be important. If the variable generation costs (fuel, CO_2) can be estimated based on market prices, they may, however, differ significantly from the actual costs incurred by generators (e.g. currently part of long-term gas supply contracts are indexed to coal). Fixed costs are primarily a result of internal transfer costs and intra-group allocation rules. Only access to generators' accounting systems (generating units representing cost centres) and to cost allocation rules would indicate the actual costs. The CREG has not, to date, ever been able to see this information, despite repeated requests.

  Providing for a fair margin also paves the way to tough negotiations.

It does not protect consumers from price spikes and represents an additional cost to customers

On the basis of foreign experiences, in order to function well the mechanism needs to have a legal framework setting out:

- the life cycle of the mechanism (determined according to the date the RES will be able to enter the market without subsidy);

- the maximum reserve volume (an annual review will be conducted as new investments are developed);

- activation rules:
  - to avoid the adverse effects described above, total withholding of the capacity from the market (made available to the TSO throughout the year) and its exclusive use in the day ahead and balancing markets as a last resort solution, appears to be the most suitable;
  - the strike price of the reserve should therefore be higher than the price of the last commercial bid (and below the VoLL).

- penalties. The TSO should ensure the capacity is actually available, and financial penalties should be provided for if this is not the case. These penalties should act as a barrier to withholding capacity from the market. Their amount should be deducted from the cost of the measure.

It is important that the mechanism's operating framework is transparent and stable.

In addition, remuneration that goes beyond covering costs (fair margin) does not seem justified, since units that could incorporate the reserve are fully depreciated, no longer offer any economic value for their operators, and allow them to postpone demolition costs.

The passing on of the reserve cost to consumers should be based on peak load.

The integration of additional demand reduction capacity should be encouraged. This could stimulate reactive demand and represent a competitive alternative to generation capacity, which could reduce the cost of the reserve. If the methods for activating the reserve were less restrictive than those of ancillary services, new suppliers could offer their services. Competitive ancillary services of demand response capacity should not, however, be withheld from the market.

The creation of reserves shared between neighbouring countries could be looked into. Germany intends to include Austrian units in its R4 strategic reserve. This is possible because these two countries constitute a single regulation zone. The IGCC project for pooling the activation of secondary reserves currently underway could also be a source of inspiration.

The mechanism is therefore particularly suited to keeping existing units in the system with a view to exceptional use (last resort solution). It is, however, not ideal for remunerating the RES back up service, insofar as the units have to be used often.

Regular activation of the reserve, i.e. when prices do not reach significant peaks, would require larger capacity to be withheld from the market, some of which could otherwise be integrated in the merit order, influencing the increase in the price of electricity in the day ahead market.

The use of the reserve should therefore be one-off and treated as a temporary measure, pending takeover by new investments offering the required flexibility, and pending the integration of RES in the market.

The Wathelet plan therefore proposes a second measure designed to encourage investment in new, flexible generation units. The restricted ministerial committee of 24 July 2012 replaced the tender mechanism in order to foster the creation of CCGTs initially offered though a “mechanism encouraging investment in new capacity that guarantees, after the closure of two nuclear plants (Doel), both security of supply and the development of renewable energy, thanks to the greater flexibility of this new capacity”.

V.2.2 Insurance against lack of profitability

Subsidisation as the main driver for investment

78. The mere mention of implementing a capacity remuneration mechanism, or any other form of support mechanism, can make the measure inevitable, even in a market with sufficient investment projects. Debate on this issue is in fact likely to postpone investment decisions, since it offers the prospect of additional revenue.

79. Furthermore, implementing measures that incentivise investment which are not coordinated at European level pose a real risk of overbidding.

Financial structure of a CCGT

80. Liberalisation of the electricity market has made the investment environment more uncertain. There are uncertainties surrounding the selling price and the quantities sold. Therefore, the larger the investment in terms of capital, the higher the cost of the hedging risk.

Compared to the cost structure of other generation technologies operating in baseload, CCGT units have low fixed costs and high variable costs, which means they can only be usefully integrated in the merit order during semi baseload or semi peak load periods, when the selling prices of electricity in the day ahead market are sufficient to cover such costs.

This cost structure makes them particularly well suited to intermittent generation, insofar as the costs to be borne by the unit on shutdown are relatively low.

Consequently, at present, total activity shutdown at the most recently recorded CCGTs does not necessarily affect their profitability over their life cycle.

However, since these are units called on to operate in more of a marginal capacity, their long-term profitability is only assured if the market price allows for a margin on variable costs that is sufficient to cover the fixed costs[18]. The more the number of operating hours decreases, the higher the margin on the kWh sold should be in order to cover the fixed costs.

Spot spreads are used to assess this margin. However, this concept should be used with caution. Spread does not calculate the profitability of a generating unit, or the profit margin resulting from the sale of electricity in the market.

Meaning of spark spread

81. As CREG stated in its study (F)110203-CDC-1036 on 'analysis of the spread concept', clean spark spread, namely the difference between the price of electricity and its estimated short-term variable generating costs (gas and CO_2) are only a rough approximation of the short-term profitability of gas power plants.

For example, using consistent returns cannot accurately assess the profitability of each plant, and they could therefore be overvalued or even undervalued. Furthermore, the marginal costs accounted for in assessing these spreads do not include all marginal costs, such as those associated with transporting fuel or O&M costs. This problem is exacerbated when spreads are considered in the longer term.

Furthermore, the prices on stock exchanges do not necessarily match the selling price of gas, which may be lower or higher depending on long-term supply contracts. This also applies to the purchase price of fuel and CO_2 quotas. For example, as CREG noted in its study 116[19], in 2011 the two main Belgian electricity generators were able to offer supply, for part of their generation, through a long-term contract indexed to coal significantly below the average price of spot supplies at the Zeebrugge Hub.

The actual profitability of a generating unit is therefore only known by its operator and is not disclosed.

[18] Inframarginal units use inframarginal rent to cover these costs
[19] Study (F)120628-CDC-1169 on the price-cost relationship in the Belgian natural gas market in 2011, 28 June 2012

82. Furthermore, spreads are not an indicator of profitability of the sale of electricity in the market. A negative spread does not mean a sale at a loss.

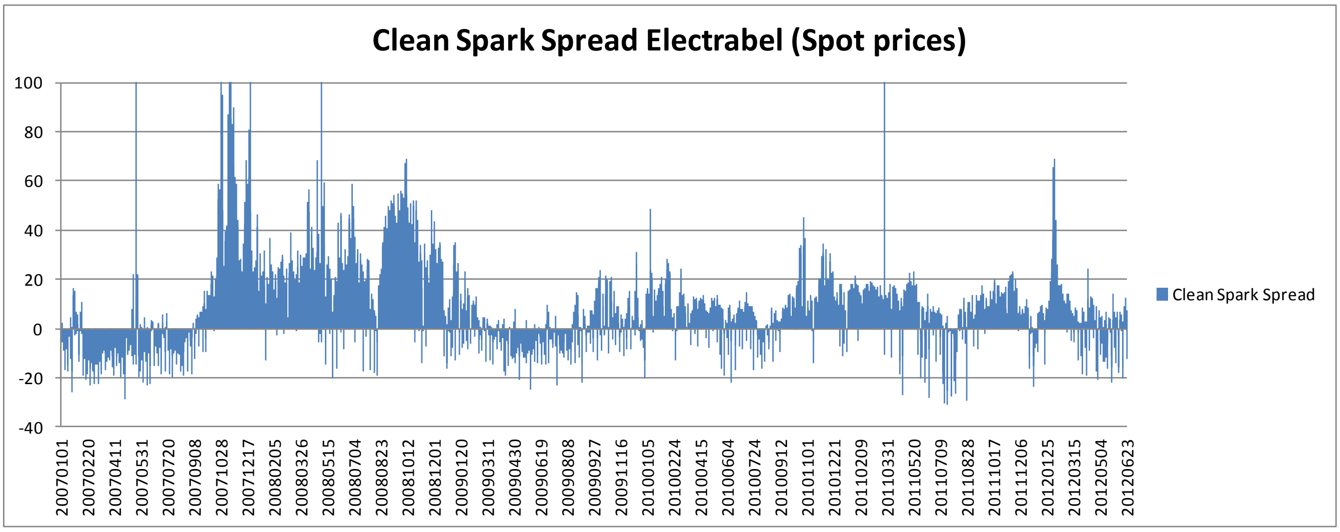
Most sales are through contracts negotiated one to three years in advance. On signing these contracts, the generator hedges their risk by purchasing forwards of gas and CO_2 in order to secure its margin.

Between the purchase of these forwards and immediately before delivery, they can engage in trading in order to optimise their position in these markets and to generate, if necessary, an additional margin.

The spread only occurs in the day ahead market, when the supplier chooses most profitable way to supply their customer. They thus favour either the available generating unit whose spread is highest, or purchasing electricity in the market offered by a domestic or foreign generator whose generation costs are lower, as well as the resale of gas and CO_2.

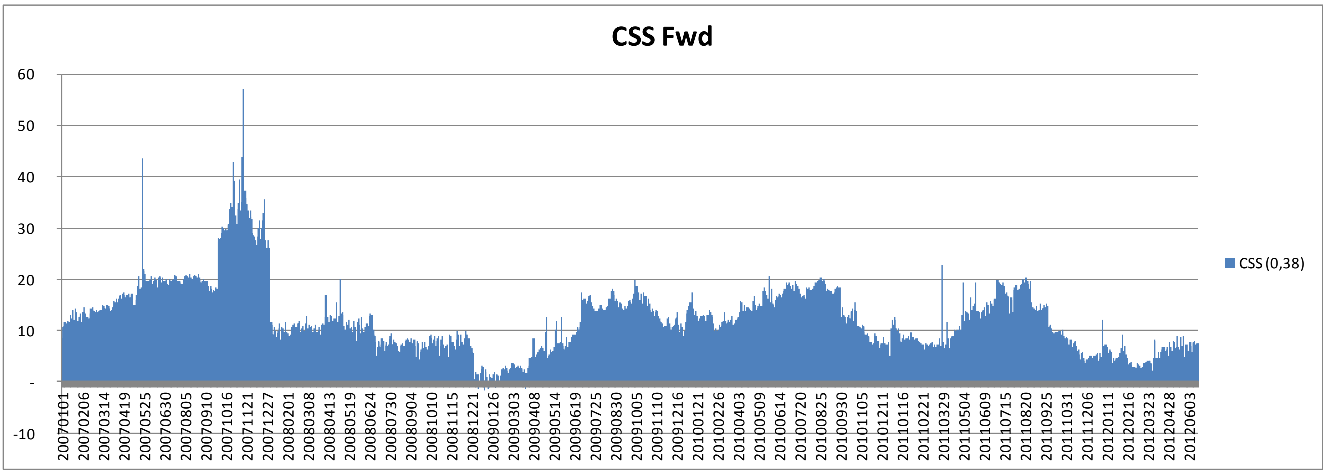
To illustrate this, CREG has calculated the spark spread based on spot prices (chart 1) and forward prices of electricity, gas and CO_2 (chart 2).

Chart 1: Illustration of the calculation of clean spark spread of a CCGT unit based on the spot prices of electricity, gas and CO_2



Source: CREG

Chart 2: Illustration of the calculation of the clean spark spread of a CCGT unit based on the Y-1, Y-2 and Y-3 forward prices of electricity, gas and CO_2[20]



Source: CREG

Positive values indicate, for example, that contracts for the sale of electricity agreed between 2008 and 2010 would cover the variable costs of production of a CCGT in 2011 and also cover, at least partially, the fixed costs.

The low current operating rate of CCGTs can be explained by the fact that the generator has, in the day ahead market, cheaper electricity supply resources and/or can perform an arbitrage in the gas market.

This situation has already been seen in the past at EdF-Luminus, which mostly preferred to purchase electricity rather than to generate it from its gas plants.

The level of aid allocated should therefore be considered in this context. It would be paradoxical to subsidise unused the generation technology of generators that are also making substantial margins on their sales.

[20] The forward price of gas is obtained by taking into account a forward supply at 90% (long-term contract and forward purchases), and at 10% in the spot market. The average price of forward purchases is obtained on the assumption that the plants use the long-term total volume contracted and that the remainder ('long-term contract' volume to total volume of gas consumed by the plants ratio) is purchased in the forward market (Y-3, Y-2 and Y-1 forward). The use of 100% of the 'long-term contract' volume by the plants is a working hypothesis that is not necessarily consistent with reality. It should also be noted that from 1st October 2012, the entry-exit model for gas transmission gives the customer access to marketplaces, even if a point of delivery is specified in the contract. Moreover, uniform distribution of volumes across all plants is a conservative working hypothesis.

Cost-benefit analysis over the project life cycle

83. The Wathelet plan sought to offer investors guaranteed ex-post yearly returns. This proposal is not consistent with the economic outlook. The profitability of an investment project is assessed based on its entire useful life (at least 25 years of operation for a CCGT; the oldest CCGT unit in the Belgian system entered service in 1971).

To make a decision, the private investor calculates the internal rate of return (IRR) of the project in question (discount rate balancing income and expenditure) and compares it to the expected rate of return on the investment. Various investment aids are possible:

a) Covering missing money costs or the total cost of capital

84. The objective of a capacity remuneration mechanism is to guarantee the remuneration of all fixed costs (capital costs and fixed production costs) of a peak plant[21].

As the analysis of how the PjM and ISO-NE markets work shows, this objective can be achieved in two ways: by allowing the producer to make a margin on their variable costs in the energy market and only remunerating the missing money in the capacity market (PjM), or by preventing them from making a margin on variable costs and directly remunerating all fixed costs in the capacity market (ISO-NE).

A PjM-type mechanism offers, in principle, the advantage of not having any direct impact on the energy market. However, providing assurance against lack of profitability may encourage investors to act in a less than optimal way in the market. This could, for example, lead them to make offers at a price below their marginal cost, consequently creating difficulties for other generating units.

[21] For example, Morgan Stanley Research, in a publication in June 2012 estimated that the capacity payment currently required to justify building a 750 MW CCGT was around 15 €/MWh, i.e. an annual subsidy of 80 million € at the current price of electricity and that, based on the forward prices, the subsidy should cover the entire cost of capital.

85. In both cases, a mechanism for controlling revenue and costs should be set up to prevent double capacity remuneration and unjustified increases in the end customer's bills.

This risk is real, and asymmetry of information between the generator and the regulator is important. **Generators refuse to disclose this type of information.** However, this information differs from plant to plant and from one operator to another.

<u>Examples of investment aids given to RES</u>

To encourage investment in RES, Member States have implemented mechanisms comparable to PPAs (power purchase agreements) which offer guarantees to investors of selling their entire generation (must run) at a price that ensures their expected return on investment. Although such mechanisms have proven their effectiveness in investment terms, they have often proved inefficient in cost management terms (excessive profitability of the investments).

Like the proposals discussed in Great Britain to support investment in nuclear plants and RES (Contract for Differences – CfD), the Wathelet plan swayed towards an annual remuneration mechanism for missing revenue in order to guarantee the desired profitability of the investment. Following a call for tenders, the selected project(s) would be the lowest bidders in terms of required efficiency.

***UK Contract for Differences* – CfD**

<u>Context</u>

This mechanism was included in the May 2012 energy bill. It aims to bring about an improvement in the feed-in tariffs mechanism. All low-carbon generation technologies would be eligible (RES and nuclear)

<u>Goal</u>

To stabilise revenue in order to minimise investment risk and therefore financial costs.

Mechanism

A fixed price level (strike price) is guaranteed to generators. They receive revenue from the sale of electricity in the market. If the market reference price is lower than the strike price, they receive the difference. Conversely, if the opposite is true, they will pay back the difference.

The **reference price** is:

- for intermittent generation: the day ahead price in the GB market :
- for baseload generation: the year ahead price.

The **strike price** is fixed, per technology, based on a projection of capital costs, the cost of fuel (for biomass) and of O&M costs per MWh (average levelised cost).
Initially, it would be set administratively on the basis of experts' advice. Investors who decide that the price is sufficient to go ahead with their project would bid for a CfD.

The duration would be 15 years for RES.

The cost would be shared between suppliers.

Main problems

- Poor forward market liquidity for providing a reference. To address this, Ofgem is planning made it mandatory for the six major suppliers to sell different products.

- Difficulty of establishing the strike price (the House of Lords has proposed a bidding mechanism).

- Variable costs of the measure to the public, in terms of market price trends.

Nuclear

An identical process would be established on a negotiated basis.

86. Although this mechanism is suitable for must run units, i.e. whose marginal cost of generation is low and whose generation we want to maximise, it is not sensible for semi baseload and semi peak units, which should only operate when it is economically justified. Indeed, guaranteeing that fixed and variable generating costs are covered for this type of generation would distort competition, which would disrupt the ancillary services and commodity markets.

b) Capital or interest subsidies

Conventional solutions for investment aid can be considered, such as partially covering interest charges. One such measure was included in Germany’s energy transformation plan, the *Energiewende.* A financing plan for a total of around 500 million € was decided, with a view to shutting down nuclear power plants in order to prevent a possible shortage of generating capacity. The aim was to finance eligible projects by up to 15% of the total investment. This plan proved ineffective and was discontinued in August 2012 because it may breach EU rules on state aid for this type of investment. Germany nonetheless maintained an interest subsidy mechanism granted to municipalities to help them invest.

In a classic financial set-up for investing in a CCGT, the capital contribution generally does not represent more than 15% of the total project cost. The share of equity is even lower when the guarantees of repaying the borrowed funds are high. Another technique for facilitating investment involves, during the loan repayment period (or part of that period), guaranteeing the injection of funds up to a fixed amount in advance if the revenue generated by the unit in the commodity and balancing markets proves insufficient for meeting repayment schedules. This mechanism is, however, not without risk of distorting competition.

Efficiency criteria, checks and penalties

87. Any investment aid must be accompanied by capacity efficiency, availability and flexibility criteria, as well as strict checks and financial penalties in the event of unjustified unavailability or inefficient management of the generating unit. Penalty amounts should be deducted from the cost of the measure.

Interim nature

88. As the Wathelet plan highlights, various causes are behind the current lack of profitability of CCGTs: intermittent renewable generation, too many must-run units, the high price of gas compared with electricity (due to the reduction in demand following the economic crisis, the low marginal cost of RES generation, the low price of coal and emissions allowances).

Some of these factors are linked to market mechanisms (gas/coal competition, low demand and, to some extent, the low price of quotas). We should therefore let the market function. Shale gas extraction in the USA and in Europe, and the European Commission's intervention to reduce the surplus of emissions allowances in the market may, for example, quickly restore the competitiveness of gas compared with coal.

By contrast, the disruption to the commodity market caused by the growing presence of inevitable generation by RES is a consequence of regulation. Corrective measures are therefore justified in this instance.

The integration of RES in the market should be a clearly defined objective when developing the policies on the support they should receive. This could, however, only be achieved in the medium term. We are therefore in a transitional phase during which intermittent RES generation needs to be offset by a backup service.

The need for such a service will reduce as RES are introduced into the market and as storage solutions are developed.

89. The measure should be of limited duration. It could only be justified as a transitional measure pending the following:

- **measures to mitigate the impact of intermittent generation by RES and their integration into the market**

  The random nature of RES generation is usually seen as preventing their integration into available generation capacity during peak demand periods, which requires having equivalent thermal generation capacity in order to cover peak supply. Management of intermittent generation could incorporate some of the intermittent capacity into the available capacity in order to meet peak demand.

  Intermittent generation can be mitigated in several ways:

  - by diversifying the system in order to obtain the greatest possible profusion of renewable generation (this is a limited option in Belgium);

  - by developing electricity storage resources, to provide a solution to the temporal dissociation between generation and consumption. Hydropower storage resources are very limited in Belgium, so this solution should be considered at European level. The potential for alternative storage should also be investigated (such as refrigeration units);

  - by interconnecting off-shore wind farms at European level (proposed);

  - by gradually integrating RES into the market through day ahead nominations in order to cover, at least partially, the cost of the imbalances they cause. This does not solve the problem of the reliability of their peak load, but incentivises them to anticipate their short-term generation better and keep step with demand.

- **by developing forward markets**

  In a highly interconnected market with a well-developed exchange, long-term hedging strategies should be able to be developed in order to hedge investment risk. Steps have been made towards this in Germany (quoting forwards at 6 years) and are planned in Great Britain (mandatory trading by the main suppliers in the market in order to boost liquidity).

<u>Stability and openness to new entrants</u>

90. The mechanism should be designed to enable a new entrant to compete effectively. The big players should not be given preferential treatment, which would create an additional barrier to competition in Belgium.

It must offer long-term stability, otherwise regulatory risk will be high and will greatly reduce the measure’s impact.

<u>Potential interference with the R4 strategic reserve mechanism</u>

91. The two mechanisms serve different purposes. Setting up an R4 strategic reserve seeks to keep unprofitable units that have been withheld from the market available, while investment aid concerns units that must operate in the market.

Rather than enhancing each other, the two measures can have the opposite effect: commissioning efficient CCGT units risks incentivising the decommissioning of other less profitable units at the end of their useful life and, consequently, integrating them into the reserve needed to maintain the required level of capacity. This would result in greater remuneration for capacity through this mechanism. Making support mechanisms widely applicable would call into question market liberalisation itself.

Additional short-term measures

92. In order to minimise the use of a capacity remuneration mechanism, which is complex to implement and carries significant risks of adverse effects, a study should be conducted into alternative solutions that are more in line with environmental objectives and the market.

a) Measures to promote alternative adequacy methods

93. The tendering mechanism originally proposed in the Wathelet plan only related to CCGT-type generation. However, in terms of adequacy, the capacity type (any type of generation, demand side response, interconnection or storage) is immaterial. It is the likelihood of its availability during peak consumption that matters.

Ultimately, these systems should be able to compete with each other in order to guarantee security of supply at the lowest cost (cf. PjM market).

There should be a cost-benefit analysis of other investments offering the same level of reliability:

In the short term:

- promoting demand side response. To this end, industrial customers should be helped to identify their demand side response potential and the service should be remunerated appropriately (fixed remuneration for load that can be shed and variable remuneration for any unused energy). Those responsible for balancing could deduct this capacity from their day ahead nomination. This is flexible power than can be deployed rapidly and whose marginal cost should be low;

- better use of existing interconnection capacity[22].

[22] Cf CREG study (F)111208-CDC-1129 on the relationship between physical and commercial interconnection capacity at Belgium's electricity boundaries

In the longer term:

- energy efficiency;

- investment in interconnection capacity with countries with flexible capacity (according to some estimates, hydropower reservoirs in Norway could provide 28 GW of flexible capacity to the continent, if interconnection capacity was not restricted). In this respect, it is worth highlighting the potential conflict of interest the TSO may face;

- investment to increase the flexibility of the generation system;

- investment to increase storage capacity (pumped storage stations).

b) Improving the investment climate

94. The above investment aid tool could incentivise investment decisions, but will not on its own guarantee actual investment. This is a set of measures that should be taken.

Investment can be encouraged through very specific measures such as:

- implementing permanent monitoring, for long-term security of supply;

- clarification of the country’s energy policy in the medium term (and its stability);

- simplifying and accelerating licence granting (single licence);

- making suitable sites, with facilities for connecting to the transmission system, available.

VI. CONCLUSION

95. Given the risks of energy market disruption, establishing capacity remuneration mechanisms should only be considered as a last resort, after having implemented all possible improvements to how the market functions.

96. Recourse to such mechanisms should be considered as an interim measure, and must be reversible.

97. They create an obstacle to market integration and distort competition between neighbouring countries if their implementation is not coordinated at European level.

For the Gas and Electricity Regulation Commission:

Guido Camps	François Possemiers
Director	President of the Executive Committee

ANNEX 1 – Legislation

Article 3.6 of the electricity act provides that forward studies should analyse the appropriateness of using a tendering procedure.

Article 5 specifies the arrangements.

Art. 5.<L 2005-06-01/32, Art. 5, 010; In force: 24-06-2005>

§ 1. Without prejudice to the provisions referred to in Article 21, paragraphs 1.1 and 1.2, the minister may use the tendering procedure to set up new electricity generating facilities when security of supply is not sufficiently guaranteed through:

1 the generation capacity under construction; or
2 energy efficiency measures; or
3 demand management.

The invitation to tender must take into account electricity supply offers with long-term guarantees issued from existing electricity generation facilities, provided they can meet additional needs.

§ 2. The minister must provide grounds for recourse to the tendering procedure, taking particular account of the following criteria:

1 [[1] a mismatch between the generation system and electricity demand trends in the medium and long term, based the forward study and Belgium's commitments to reduce greenhouse gas emissions and to increase energy generation from renewable sources in particular;][1]
2 investments designed to increase generating capacity, notwithstanding energy efficiency investments;
3 the public service obligations referred to in Article 21.

§ 3. The network administrator's opinion in relation to the size of the generation system and the impact of imports is required prior to launching the tendering procedure.

§ 4. The King shall determine [[1], after consulting the Commission,][1] the terms of the tendering procedure, ensuring the following:

1 that competition is fostered through invitation to tender;
2 the transparency of the procedure, particularly the technical specifications and criteria for awarding the tender;
3 the equal treatment of all bidders responding to the invitation to tender;
[[1] 4 compliance of the tender documentation submitted by the bidders with the criteria set out in Article 4 and its implementing regulations.][1]

The specifications [[1] drawn up by the Directorate-General for Energy][1] may contain incentives to promote the construction of electricity generation facilities forming the subject of the tender.

Pursuant to Article 21, the King may determine, by decree subject to deliberation in the Council of Ministers, public service obligations enabling the financing of the incentives referred to above.

[[1] § 4a. The details of the tendering procedure shall be published in the Official Journal of the European Union at least six months prior to the closing date for tenders.

The specifications are provided to all interested undertakings established in the territory of a Member State of the European Union, so that they can be allowed sufficient time to submit a bid.

With a view to ensuring transparency and non-discrimination, the tender specifications shall contain a detailed description of the contract specifications and of the procedure to be followed by all tenderers, as well as the selection of tenderers and the award of the contract, including incentives.][1]

§ 5. [[1] After obtaining the opinion of the authorities consulted pursuant to the procedure in Article 4, the minister shall, on the basis of the criteria referred to in Article 4, § 2, select the successful tenderers. This has the effect of individual clearance for electricity generation within the meaning of Article 4.][1]

[[1] § 6. The Directorate-General for Energy is responsible for the organisation, monitoring and checks on the tendering procedure referred to in § § 1 to 5. In this respect, the Directorate-General for Energy shall take all necessary measures to ensure the confidentiality of the information contained in the tenders.][1]

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(1) < L 2012-01-08/02, Art. 6, 026; In force: 21-01-2012 >