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Accompanying the document

REPORT FROM THE COMMISSION

Interim Report of the Sector Inquiry on Capacity Mechanisms

{C(2016) 2107 final}

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1. INTRODUCTION

1.1 Concerns about the security of electricity supply

Europe's electricity sector is experiencing a period of unprecedented transition. Liberalisation and decarbonisation have profoundly changed the way electricity is generated, traded and consumed in the Union, pursuing a more sustainable and at the same time affordable electricity market. Renewable energy sources have grown rapidly and 10% of total electricity is now sourced from variable renewable electricity, such as wind or solar.

The large-scale roll-out of renewables combined with the overall decline in demand and the decreasing cost of fossil fuels have curbed the profitability of conventional generators and reduced incentives to maintain existing power plants or invest in new ones. In many Member States, these developments have been accompanied by increased concerns about security of supply. Member States are concerned that the electricity market will not produce the investment signals needed to ensure an electricity generation mix that is able to meet demand at all times.

Some Member States have reacted by taking measures designed to support investment in the additional capacity that they deem necessary to ensure an acceptable level of security of supply. These capacity mechanisms pay providers of existing and/or new capacity for making it available.

When introduced prematurely, without proper problem identification or in an uncoordinated manner, and without taking into account the contribution of cross-border resources, there is a risk that capacity mechanisms distort cross-border electricity trade and competition. For example, they may reward new investments only in certain types of generation or exclude demand response. They may also encourage investment within national borders when it would be more efficient to reinforce interconnection and import electricity when needed.

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1.2 The Energy Union and the Market Design Initiative

Concerns about the security of electricity supply have been raised by the Commission in the framework of the Energy Union.[1] Under the internal market dimension of the Energy Union, the Commission envisages to take action in the broader area of electricity market design and security of electricity supply both of which are related to generation adequacy. More specifically, the Energy Union strategy states that the Commission will establish a range of acceptable risk levels for supply interruptions, and an objective, EU-wide, fact-based security of supply assessment addressing the situation in Member States. This will take into account cross-border flows, variable renewable production, demand response and storage possibilities.

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[1] Communication from the Commission, 'A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy', COM(2015) 80 final

To obtain stakeholders' views on these ideas, the Commission launched public consultations, firstly, on a new energy market design[2] and, secondly, on a review of the Directive concerning measures to safeguard security of electricity supply.[3]

This sector inquiry aims to contribute to the Commission's Energy Union agenda and the development of a new market design that is fit for the future by assessing to what extent capacity mechanisms are appropriate instruments to ensure sufficient electricity supply whilst at the same time minimising the distortion of competition or trade in the internal electricity market.

1.3 The Energy and Environmental Aid Guidelines

The Guidelines on State aid for environmental protection and energy 2014 – 2020 ('EEAG')[4] include specific rules for assessing capacity mechanisms. The Commission has already applied these rules to a capacity mechanism notified by the United Kingdom and two French capacity mechanisms.[5]

The sector inquiry is not intended to provide a State aid assessment of the existing or planned capacity mechanisms in the Member States included in it. The compliance of those mechanisms with State aid rules is carried out exclusively in the context of State aid decisions.

The present report rather aims to gather and present information on the functioning of capacity mechanisms and draw tentative conclusions which will help with the application of EEAG. The interim report and this Staff Working Document are intended to test these findings and tentative conclusions by putting them forward for consultation and the structure of this document is set-up accordingly.

The information gathered in the sector inquiry will enable the Commission to understand better:

- whether, and to what extent, it is necessary that Member States grant State aid to ensure security of electricity supply;

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[2] COM(2015)340 final.

[3] https://ec.europa.eu/energy/sites/ener/files/documents/DG%20ENER_ConsultationPaperSoSelectricity14July.pdf

[4] Guidelines on State aid for environmental protection and energy 2014-2020 (EEAG) (OJ C 200 of 28.06.2014, p. 1).

[5] For the British capacity market decision see Commission decision C (2014) 5083 final of 23.7.2014 in Case SA.35980 (2014/N-2) – United Kingdom - Electricity market reform – Capacity market. The public version of the decision is available at: http://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf. The Commission opened formal investigations into the French country-wide capacity mechanism (SA.39621) and the tender for a gas-fired power plant in Brittany (SA.40454) on 13 November 2015. See: http://europa.eu/rapid/press-release_IP-15-6077_en.htm. The Commission's decision on the country-wide capacity mechanism is publicly available (in French) at: http://ec.europa.eu/competition/state_aid/cases/261326/261326_1711140_20_2.pdf and for the tender for a gas-fired power plant in Brittany at: http://ec.europa.eu/competition/state_aid/cases/261325/261325_1711139_35_3.pdf.

- what types of capacity mechanisms are most suitable to ensure security of electricity supply, and under which conditions capacity mechanisms risk distorting competition between capacity providers[6] and cross-border trade;
- how capacity mechanisms can complement the internal energy market rather than undermine its functioning;
- how capacity mechanisms for security of supply interact with the decarbonisation objectives[7]; and
- how compliance with State aid rules can be ensured when Member States design and implement capacity mechanisms.

To that end, the Commission has, as a first step, examined the reasons behind the introduction of capacity mechanisms and their design features. It has examined a number of existing mechanisms as well as a number of mechanisms that Member States plan to put in place. The Commission has looked at those mechanisms in the wider market context including in particular the growing share of renewable energy.

1.4 The sector inquiry: what has the Commission done so far?

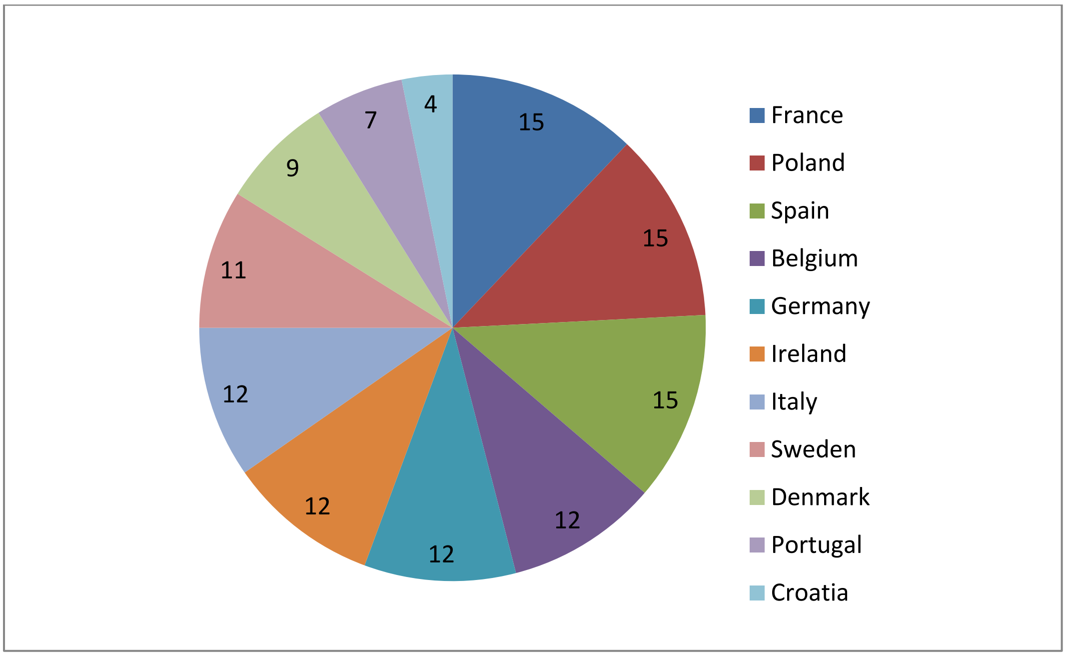
In order to prepare the interim report, the Commission sent out detailed questionnaires to over 200 public bodies, energy regulators, transmission system operators ('TSOs') and market participants commercially active on any of the eleven markets under assessment: Belgium, Croatia, Denmark, France, Germany, Ireland, Italy, Poland, Portugal, Spain and Sweden. The Commission selected these eleven Member States because they have either introduced or are considering introducing one or more capacity mechanisms. The combination of Member States was also chosen to constitute a representative sample of the different types of capacity mechanism being developed in Europe.

The Commission received in total 124 replies. An overview of the number of replies per Member State is given in Figure 1. More detailed pie charts, providing an overview of the type of respondents per Member State, are given in Annex 1 to this Report.

[6] For instance between power generators and demand response operators

[7] For instance by excluding certain technologies, such as lignite (see SWD, chapter 5.2.2.1, page 64) and in accordance with point 220 of the EEAG

Figure 1: overview of replies by Member State



Source: European Commission

The Commission also organized three workshops with Member States dedicated to various questions related to capacity mechanisms, for instance on adequacy assessments, design features and cross-border participation in capacity mechanisms.[8] In addition, bilateral meetings were held with the Agency for the Cooperation of Energy Regulators (hereafter, ACER), the European Network for Transmission System Operators in Electricity (hereafter, ENTSO-E), the International Energy Agency (hereafter, IEA) and European associations of electricity producers, consumers, storage operators and demand response providers. Finally, the Commission has made use of a wide array of public sources of information as well as specialist literature and publications on the topic.

1.5 Set-up of the Staff Working Document

It is the aim of this Staff Working Document to present the findings of the sector inquiry regarding the current practice applied by Member States when contemplating, adopting and operating a capacity mechanism and to draw tentative conclusions. The public consultation on the interim report and this Staff Working Document is intended to test these findings and tentative conclusions.

The first two chapters aim to define the scope of the work and to provide the relevant market context within which the issue of capacity mechanisms has arisen. Chapter 2 presents an overview of the state of the electricity market in the EU as a whole and in particular in the eleven Member States under scrutiny. It explains why many Member States are concerned about the continued capability of their electricity system to meet demand at all times and are

[8] http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html

therefore using or considering to introduce capacity mechanisms. It subsequently assesses what drives investments in generation capacity and describes the market and regulatory failures that impact investment decisions in the electricity market. A number of market improvements are discussed as means to address the identified failures, whereby it is recognised that residual failures may persist.

In subsequent chapters the ability of capacity mechanisms to address these residual market and regulatory failures is analysed. Chapter 3 provides a taxonomy of capacity mechanisms and categorises the capacity mechanisms that have been encountered in the eleven Member States subject to the sector inquiry. Chapter 4 provides an overview of the ways in which Member States assess their generation adequacy and the role of reliability standards in that assessment. Chapter 5 presents in a high level of detail the preliminary findings of the sector inquiry vis-à-vis the design features of the different capacity mechanisms, organised in three categories: eligibility, the allocation process and the capacity product. On the basis of the findings presented in the previous chapters, finally Chapter 6 draws tentative conclusions regarding the suitability of each type of capacity mechanism to address generation adequacy concerns.

2. INCREASED GENERATION ADEQUACY CONCERNS

Generation adequacy concerns arise in the context of the transition of Europe's electricity sector from national centrally-managed systems based on conventional fuel to a liberalised and competitive system with substantial shares of variable renewables. This chapter assesses the changes in the sector so far and presents expected future developments. The chapter also describes the reasons why the eleven Member States of the sector inquiry have implemented or are planning a capacity mechanism. Finally, it underlines the importance of ensuring that the introduction of a capacity mechanism does not replace market reforms that are better suited to address to core of the problem.

2.1 The electricity sector in transition

2.1.1 The liberalisation of electricity markets

Liberalisation and the creation of an internal energy market have been at the heart of EU energy policy since the early 1990s. The Third Energy Package[9], adopted in 2009, has resulted in the complete unbundling of the supply and generation arms of vertically integrated undertakings from their transmission activities, thus creating fully independent transmission system operators (TSOs) and paving the way for competition to occur in the generation and supply segments of the sector.

In the last decade competitive wholesale markets have appeared in a large majority of Member States and cross-border trade has intensified significantly. The implementation of market coupling[10] has enabled an optimal use of interconnection capacities, ensuring that electricity automatically flows from areas of low prices to areas of high prices, and the most efficient plants run not just nationally but in entire regions. Harmonised trading rules for trading in regions comprising several Member States[11] have fundamentally changed the business models of generators and suppliers alike. They increasingly take into account cross-border flows and hedge their positions long term, for instance by closing long term contracts and/or buying transmission rights, and optimize their positions in the day-ahead and increasingly in even shorter term intraday markets.

Liberalisation has implied a transition from central planning of investments in generation and capacity towards decentralised decision-making. On the one hand, investment decisions on

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[9] Directive 2009/72/EC concerning common rules for the internal market in electricity, Directive 2009/73/EC concerning common rules for the internal market in natural gas, Regulation (EC) No 714/2009 on conditions for access to the network for cross-border exchanges in electricity, Regulation (EC) No 715/2009 on conditions for access to the natural gas transmission networks and Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing an Agency for the Cooperation of Energy Regulators.

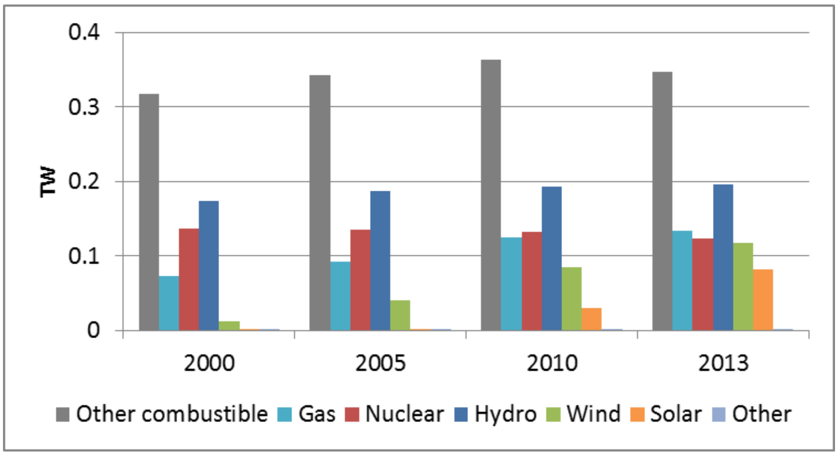
[10] The term market coupling refers to the implicit allocation of both the electricity and the available interconnection capacity at the same time, instead of separately via explicit auctions.

[11] See e.g. the organisation of trading with "capacity calculation regions" of several Member States (Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management, OJ L 197, 25.7.2015, p. 24–72).

generation capacity and on transmission capacity are no longer taken jointly. On the other hand, investment decisions in generation capacity are taken autonomously by private undertakings operating in electricity generation. This shift, together with the new organisation of the relation between generators and TSOs through unbundling, requires an adaptation of previous adequacy planning mechanisms, and a robust framework for regulatory supervision of generation adequacy, including a clear definition of the roles of the different actors in adequacy planning. Otherwise, the uncertainty about when and where investments in generation capacity will take place could be uncomfortable for TSOs from a technical perspective, but also policy makers who bear the ultimate political responsibility for secure electricity supplies. These considerations are particularly relevant given that Europe's generation fleet is ageing, potentially creating a need for investments in generation capacity.

Installed generation capacity has substantially increased over the last two decades, as a result of investments by both incumbent generators and new entrants. These investments focused notably on wind and solar technologies, but also on combustible fuel technologies, especially gas.

Figure 2: Evolution of installed generation capacity by technology in the EU28 as a whole[12]



Source: Eurostat.

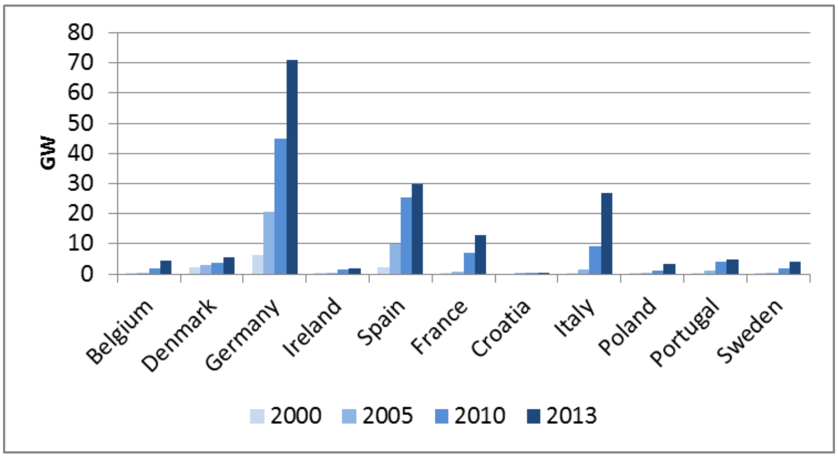
2.1.2 Decarbonisation policies

The energy sector is a large contributor to the EU's carbon footprint but also contributes in a variety of ways to realise emission reductions. Power companies and industrial installations in the EU are covered under the EU Emissions Trading System (ETS), which puts a price on carbon, ensuring that the costs of fossil fuels reflect their carbon intensity. The ETS is a market based system, in which power companies can choose whether to buy allowances on the market or to reduce emissions. As the overall limit on the number of allowances declines

[12] Category "Other combustible" is the result of subtracting "Gas turbines" and "Combined cycle" from the category "Combustible fuels" in Eurostat database on "Infrastructure Electricity Annual data" [nrg_113a]

and technologies for decarbonisation are further developed, this provides a stronger incentive to reduce emissions at a low cost. Additionally, the political determination to encourage renewable generation through support schemes, resulting in national renewables targets and the Renewable Energy Directive[13], has contributed to an impressive growth in the share of renewables in the EU's energy mix. The increasing maturity and decreasing investment costs of these generation technologies (the 'learning curve' of renewables), as well as the expectations of sustained increasing demand for electricity prior to the economic crisis have further stimulated the development of RES. By 2013, 26% of the EU's electricity is generated from renewables and about 10% of total electricity is sourced from intermittent renewable electricity, whose availability essentially depends on variable factors outside the control of the plant operator, like the weather conditions in the case of wind and solar.[14]

Figure 3: Evolution of wind and solar generation capacity by Member State



Source: Eurostat

In most of the eleven Member States covered by this inquiry the generation mix now consists of substantial shares of variable renewable energy sources (RES). Wind and solar generation technologies have achieved the largest shares of installed capacity in Denmark (40%), Germany (38%), Spain (28%) and Portugal (25%). The shares of variable RES are expected to increase further, in particular as some Member States are still making progress and increase the share of renewables in their country in order to reach their 2020 targets.

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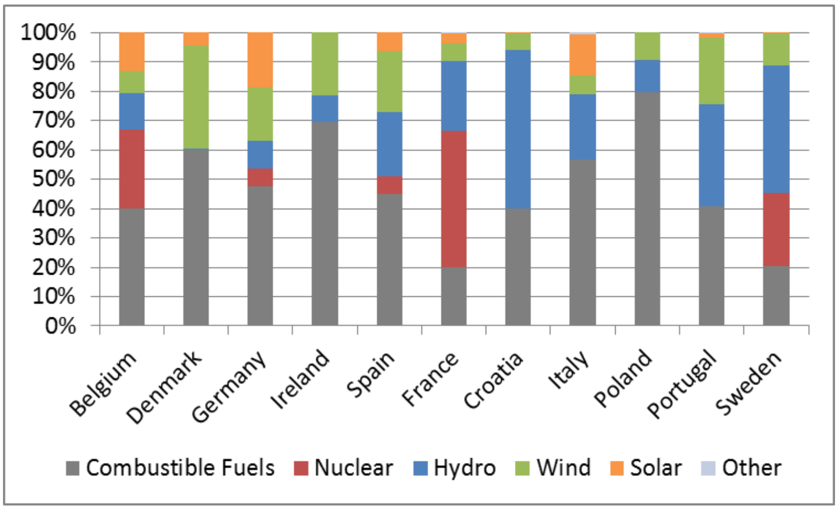
[13] Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC

[14] European Commission, Renewable energy progress report {SWD(2015) 117 final}

Figure 4: Installed generation capacity by technology (in %) in each of the 11 MS in 2013



Source: Eurostat

The significant increase in renewables has important side-effects for security of electricity supply. The relatively unpredictable nature of certain variable renewable sources such as wind and solar makes the electricity system more difficult to manage for TSOs. Moreover, due to their low marginal costs, RES reduce the running hours of conventional generation. This effect has been reinforced by further decarbonisation and environmental policies, including at a European level, such as the European-wide Emissions Trading System, the Energy Efficiency Directive[15], the Large Combustion Plant Directive[16], and the Industrial Emissions Directive[17].

2.1.3 Concerns about security of supply

Security of supply is one of the three core objectives of EU energy policy. In the electricity sector, security of supply has a short term and a long term dimension. In the short term, it is important that the TSO, who is responsible for system security in real time, has sufficient instruments at its disposal to ensure balance between demand and supply. In the long run, the electricity system needs to be fit to provide sufficient electricity to meet demand at all times and in all parts of the system.

This section discusses the impact that recent developments in European electricity markets, mainly driven by the liberalisation and decarbonisation objectives, but also the economic crisis, are having on the long term adequacy of generation capacity and security of supply. It assesses the question from three angles: how has the relation between demand and generation

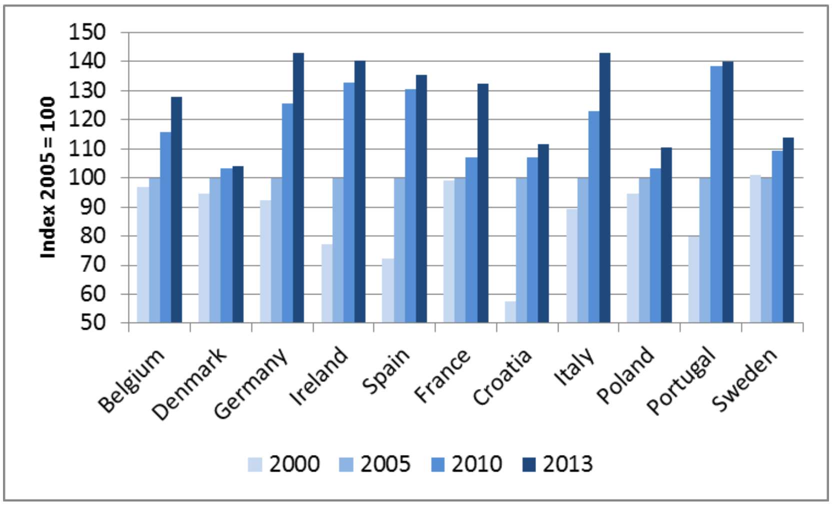
[15] Directive 2012/27/EU of the European Parliament and of the Council of 25 October 2012 on energy efficiency, amending Directives 2009/125/EC and 2010/30/EU and repealing Directives 2004/8/EC and 2006/32/EC
[16] Directive 2001/80/EC on the limitation of emissions of certain pollutants into the air from large combustion plants
[17] Directive 2010/75/EU of the European Parliament and the Council on industrial emissions

capacity developed, how have utilisation rates of power plants evolved, and how has the profitability of conventional plants been affected.

2.1.3.1 Margins between generation capacity and demand have widened

Total installed generation capacity in the EU-28 has increased by more than 30% since 2000, reaching a total of more than 1 TW in 2013. This has been a gradual increase, with the steepest growth starting in the years immediately before the economic crisis and continuing until 2011. The fact that the growth in total installed capacity continued to increase during the first years of the economic downturn is related both to the lag between investment decisions and new generation plants entering operation and to the continued support schemes, especially for renewables. While installed generation capacity has increased in all the 11 Member States investigated in this inquiry, the growth has not been evenly distributed, as shown in Figure 5.

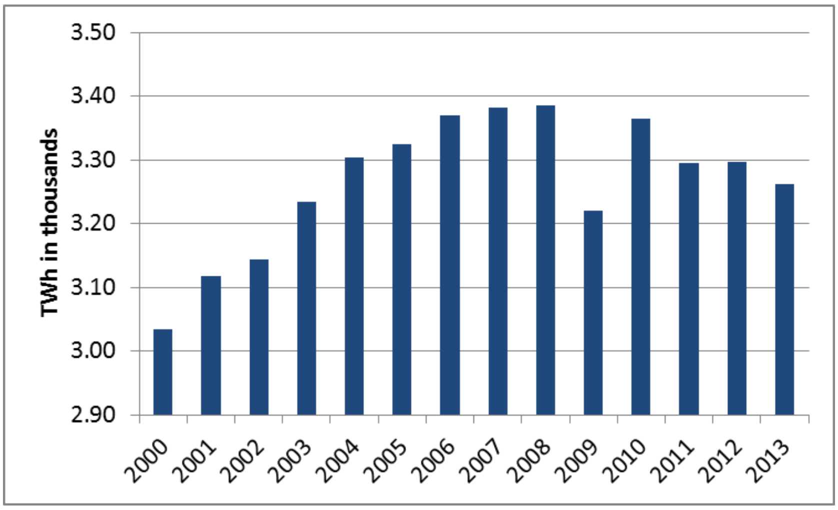
Figure 5: Evolution of installed generation capacity in each of the 11 MS



Source: Eurostat

Contrary to the inertia observed in the evolution of installed generation capacity, the production and demand of electricity was rapidly impacted by the start of the economic crisis. Production grew steeply by about 15% between 2000 and 2007, before starting to decrease during the economic downturn. Between 2008 and 2013, annual electricity generation in the EU decreased by 5%.

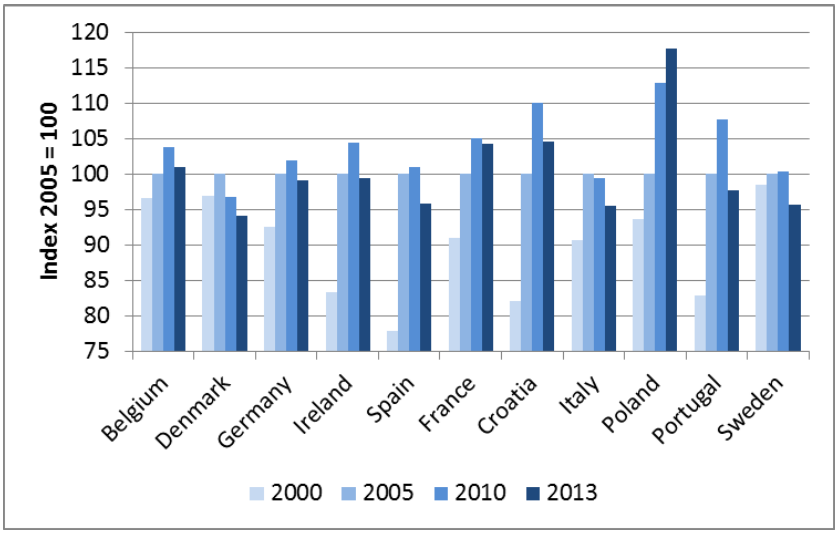
Figure 6: Evolution of generated electricity in the EU28 as a whole



Source: Eurostat

The downward trend of demand for electricity has been observed in most Member States, but with differences across them as well as with some exceptions. In Poland for example, average demand for electricity continued to grow during the entire period 2000-2013, which is consistent with the mild impact of the crisis on the Polish economy. In both France and Germany average electricity demand remained broadly stable during the years of the economic crisis. Average electricity demand dropped significantly in most other Member States, including Belgium, Croatia, Denmark, Ireland, Italy, Portugal and Spain.

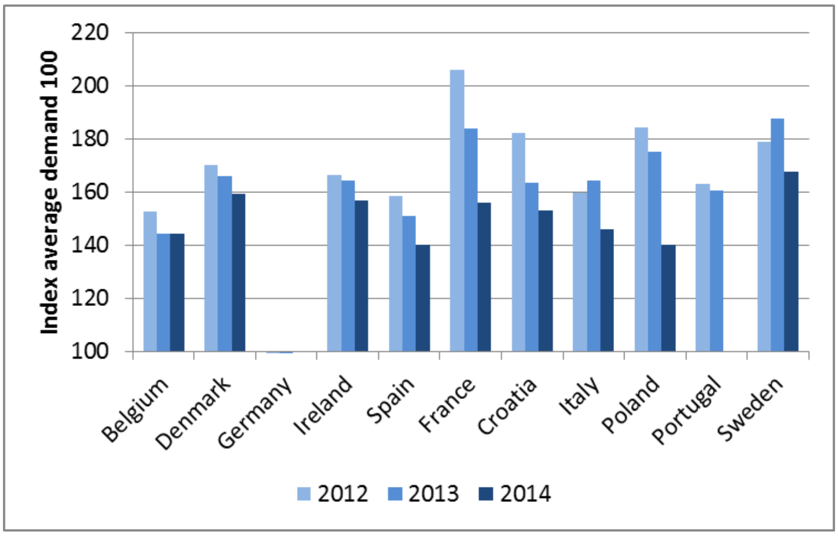
Figure 7: Evolution of final demand for electricity in each of the 11 Member States



Source: Eurostat

Similar trends have been observed for the peak demand, defined as the highest yearly demand level, of electricity in the Member States covered in the inquiry.

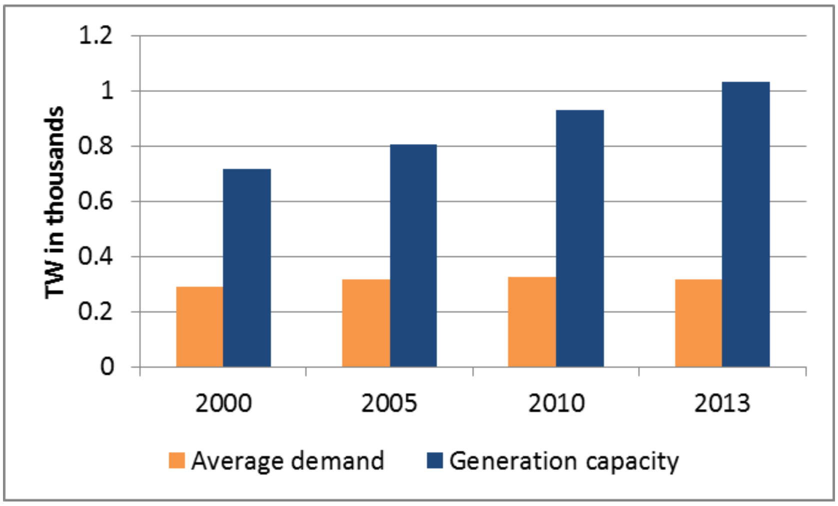
Figure 8: Evolution of peak demand for electricity in each of the 11 Member States[18]



Source: European Commission based on replies to sector inquiry

The constant increase in total generation capacity since 2000 coupled with the decrease in average demand since 2008 has widened the margin between average demand and installed capacity since the beginning of the economic crisis.

Figure 9: Evolution of average demand and generation capacity for the EU28 as a whole

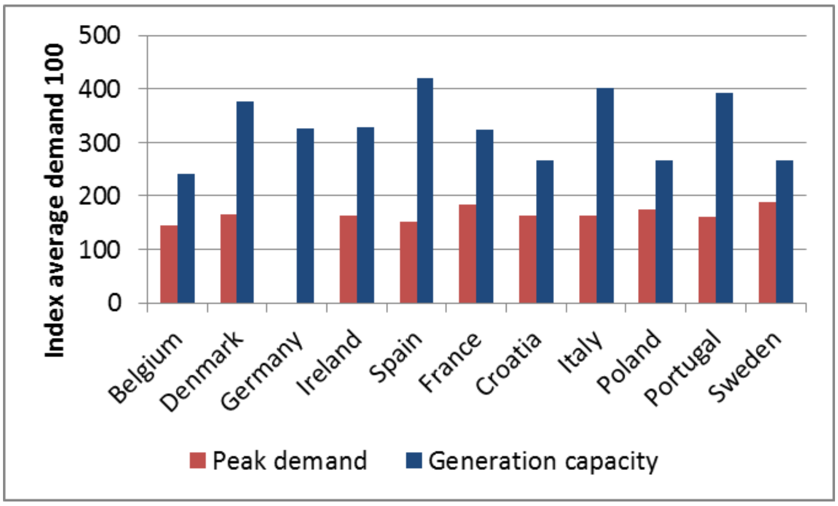


Source: Eurostat

The margin between average or peak demand and total installed capacity varies across the 11 Member States. In 2013, the margin was largest in Denmark, Spain, Italy and Portugal. At the opposite end, it was smallest in Belgium, Croatia, Poland and Sweden.

[18] This graph is based on figures provided by the Member States in the context of the sector inquiry. The figures provided by Germany were not specific enough to allow for inclusion in this graph.

Figure 10: Indexed peak demand and generation capacity in each of the 11 Member States in 2013



Source: Eurostat and European Commission based on replies to the sector inquiry

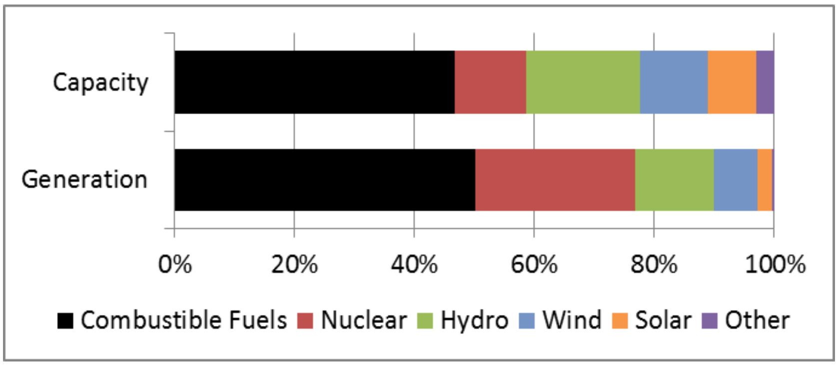
Increasing gaps between peak demand and potential supplies may appear to demonstrate that there is overcapacity in the market. However, that conclusion would be too simplistic. Resilient electricity systems typically require a supply buffer above predicted peak demand to protect themselves against unpredicted potential increases in peak demand, disruptions to supply (e.g. planned and unplanned maintenance of generation units), or interruptions in the availability of transmission infrastructure. More importantly, the aggregation of the maximum installed capacity does not take into account that each technology has a different level of availability and intermittency, which means that different generation mixes may require different margins between installed generation capacity and peak or average demand. Finally, a simple capacity margin often does not include the potential contribution of imports through interconnectors or the flexibility of the demand-side.

2.1.3.2 Capacity utilisation of conventional generation has decreased

The contribution of each technology to the effective generation of electricity does not match the share of each technology in the installed capacity mix. While in 2013 nuclear represented 13% of total installed capacity in the EU28, it produced 27% of all the electricity generated. This illustrates the fact that nuclear generation units typically run continuously most of the time during the year.

The opposite applies to hydro, wind and solar: in 2013 they represented 20%, 12% and 7% of total installed capacity respectively, but contributed just 13%, 7% and 3% to effective electricity generation. This illustrates the variable nature of these renewable technologies, which despite their low running costs cannot always generate due to their dependency on weather conditions.

Figure 11: Capacity and generation mix in the EU28 in 2013

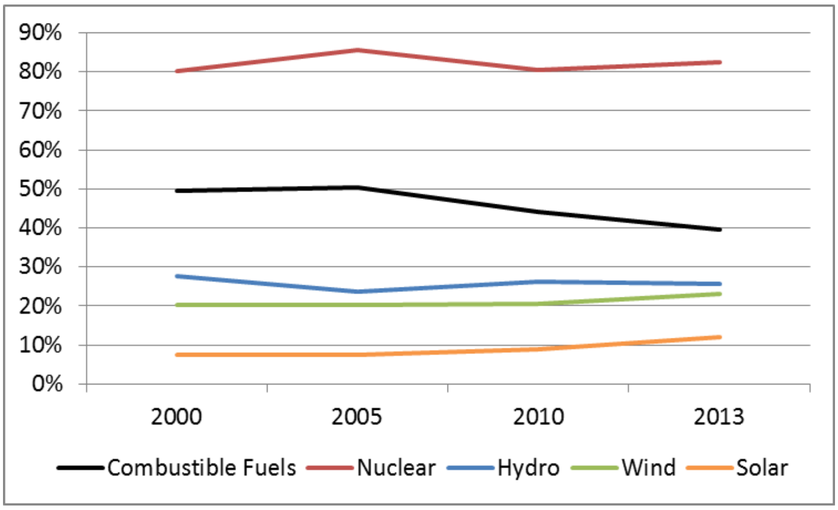


Source: Eurostat

The deviations between the share of installed capacity of each generation technology and the share of electricity generated by each technology indicate different levels of capacity utilisation across technologies. One possible measure of capacity utilisation is the ratio between the average generation per hour and the installed capacity for each technology. Figure 12 shows this measure of capacity utilisation for the EU28 by generation technology.

As expected, nuclear exhibits the highest level of capacity utilisation, stable above 80% since 2000. Capacity utilisation of hydro has also remained broadly stable throughout the period, albeit at a much lower 30%. Wind and solar have gradually increased their levels of capacity utilisation over the last years, attaining 23% and 12% levels respectively in 2013. Of particular interest is the evolution of the capacity utilisation of combustible fuels, which has significantly decreased since 2005, from 50% to 40%. Hence, the increasing weight of intermittent wind and solar in the generation mix over the last decade has been accompanied by a lower level of capacity utilisation for combustible fuel technologies, in particular gas.

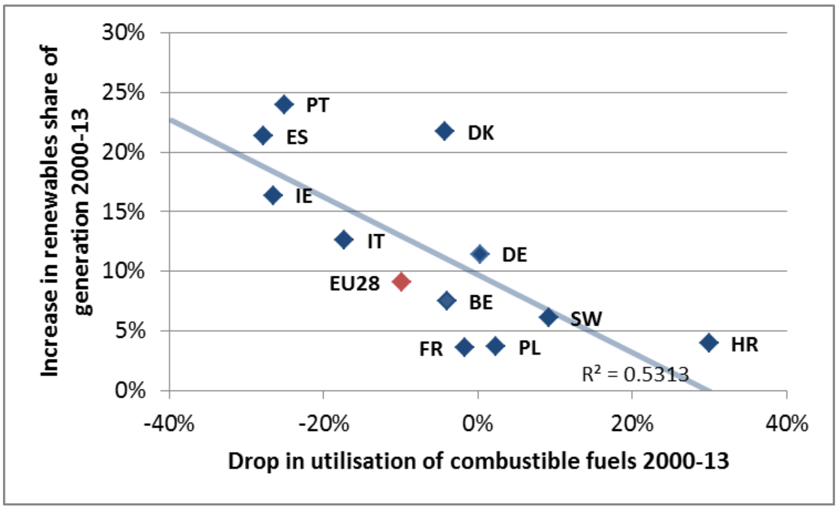
Figure 12: Evolution of capacity utilisation ratio by technology in the EU28 as a whole



Source: Eurostat

The correlation between wind and solar penetration and the drop in the capacity utilisation of combustible fuels can be further illustrated by the evidence from cross-country data. Those Member States where wind and solar have exhibited a larger increase in their contribution to electricity generation tend to be also the countries with the largest drop in the level of capacity utilisation of combustible fuels. Hence, over the period 2000-2013 in the EU28, there has been a negative correlation between the increase in the share of electricity generated from wind and solar and the drop in the capacity utilisation of combustible fuels.

Figure 13: Relation between renewable generation penetration and capacity utilisation of combustible fuels

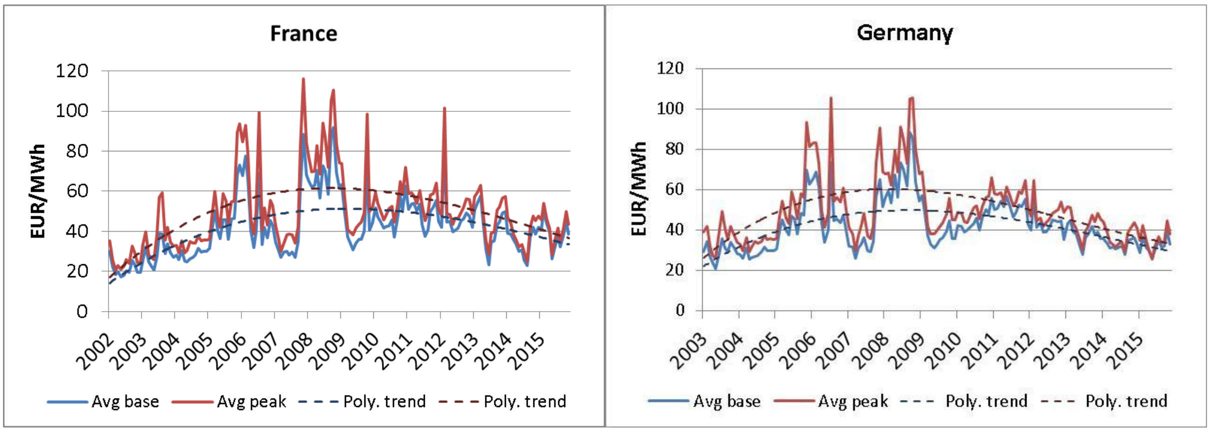


Source: European Commission based on Eurostat data

2.1.3.3 Profitability levels for conventional generation have been eroded

Wholesale electricity prices have shown both significant volatility and common trends across Member States. Figure 14 depicts the evolution of monthly average spot electricity prices in France and Germany. In both Member States, spot prices describe an upward trend in the pre-crisis years and until 2010, while a downwards trend is observed since 2011.

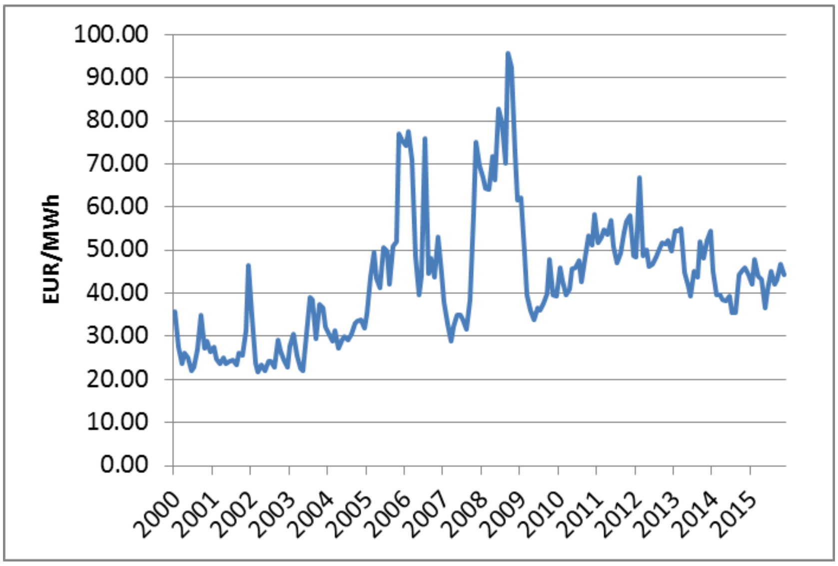
Figure 14: Evolution of spot electricity prices in France and Germany



Source: European Commission on the basis of Power Exchanges data

Figure 15 shows similar trends for a price index constructed on the basis of a larger set of European spot electricity markets.

Figure 15: Evolution of Platts' Pan European Price Index



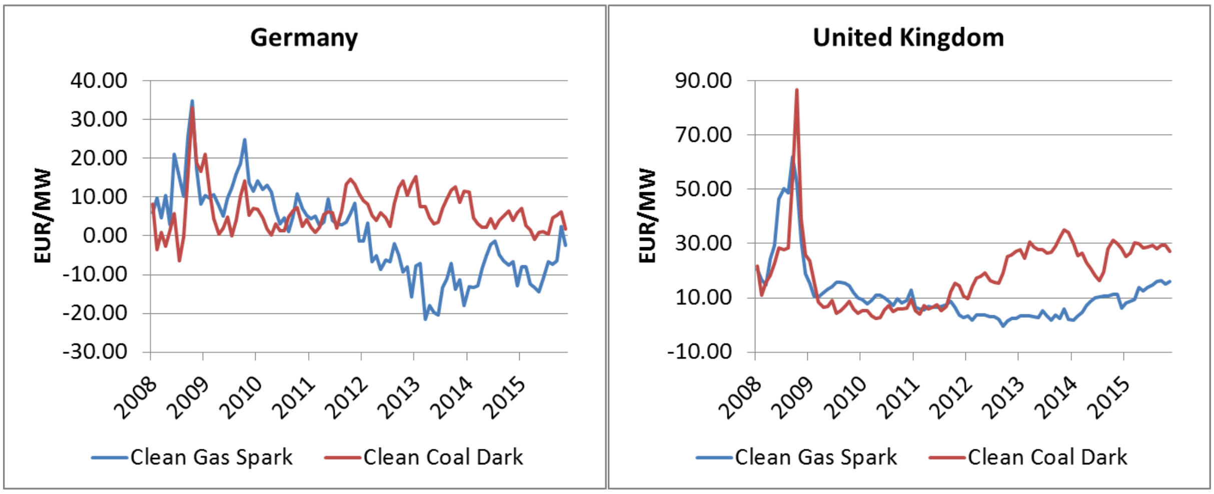
Source: Platts

The drop in electricity prices over the last 5 years is the result of a variety of developments, which includes the lower demand for electricity, the increasing proportion of renewable technologies with low marginal costs and the increasing margin between generation capacity and demand.

Lower electricity prices imply lower levels of profitability for generation technologies whose costs and capacity utilisation have remained largely stable, for instance nuclear generation. In the case of coal- and gas-fired plants, profitability depends on electricity prices and capacity utilisation, but also on the development of fuel prices. The clean spark spread and the clean dark spread[19] provide an indication of average profit margins for gas- and coal-based generation, net of EU ETS carbon prices. Figure 16 shows the evolution of these two indicators in Germany and the United Kingdom. In both Member States, the clean spark and dark spreads show an erosion of profitability levels of gas-based generation relative to coal-based generation, especially between 2012 and 2014. Recent data for 2015 seems to indicate that this trend might be reverting to some extent.

[19] The clean spark spread and the clean dark spread are indicators of the relative profitability of gas and coal. The Commission has used data from Platts in Figure 16. Platts defines its spark spreads as indicative prices giving the average difference between the cost of gas and the equivalent price of electricity on any given day. Its dark spreads are indicative prices giving the average difference between the cost of coal and the equivalent price of electricity on any given day. More information on which UK and German gas, power and coal prices were used is provided here: https://www.platts.com/IM.Platts.Content/methodologyreferences/methodologyspecs/european_power_methodology.pdf

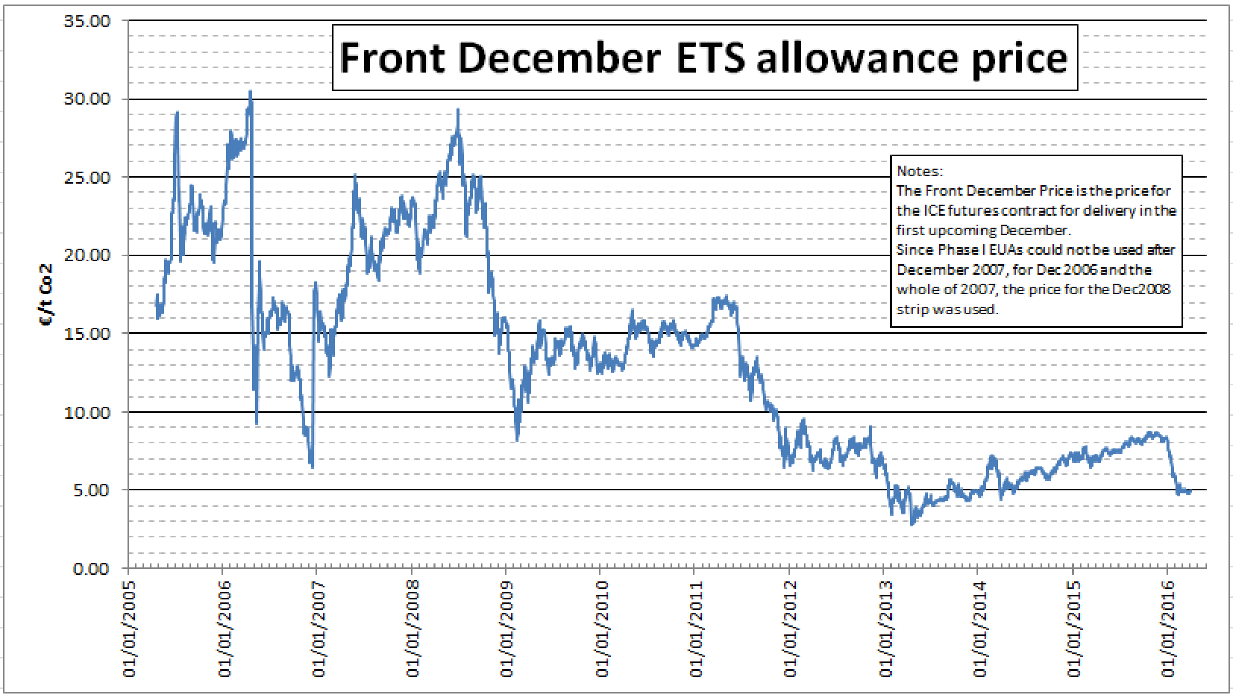
Figure 16: Evolution of clean gas spark and coal dark in Germany and United Kingdom



Source: Platts global commodity prices, to add: assumption on efficiency of gas fired

The decrease of EU ETS prices since 2008, and especially since 2011, as shown in Figure 17, has reduced overall emission-related costs for combustion technologies. The relative impact has been more favourable for coal-based generation than for gas, due to the higher carbon emissions of the former.

Figure 17: Evolution of EU ETS carbon price

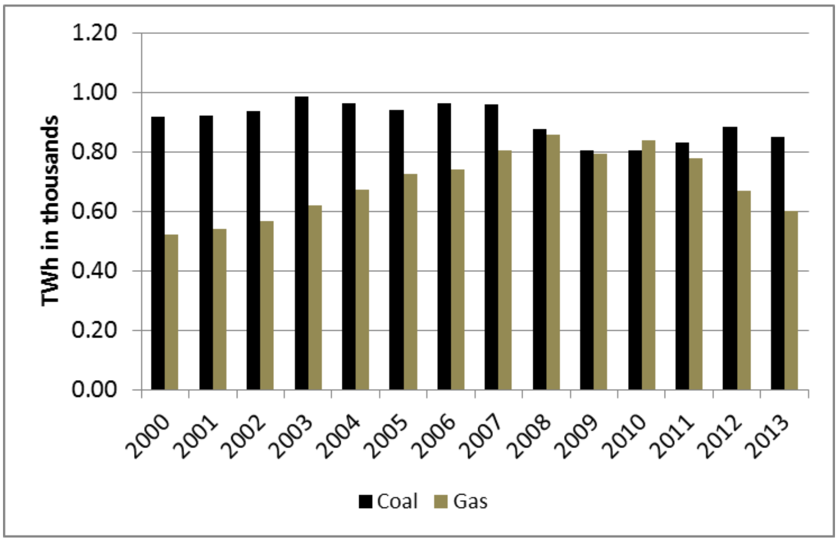


Source: European Commission, based on ICE data

Additional factors that might have contributed to the increase in the relative profitability of coal-fired power plants vis-à-vis gas-fired power plants in Europe are the massive shift to shale gas in the US and the switch from nuclear to gas in Japan,.

All these factors have contributed to make coal-based generation less costly on average than gas-based generation. Gas-based generation of electricity increased steadily until 2010, but has significantly decreased since 2011. Conversely, coal-based generation has increased since 2010, reflecting the change in the relative positions of gas and coal in the merit order curve.

Figure 18: Evolution of gross generation of coal and gas in the EU28



Source: Eurostat

Coal- and gas-based generation are the main source of flexible generation. In case renewable sources are not available, gas generation is considered, among fossil fuels, to be a particularly suitable back-up for RES, due to its ability to ramp up and down relatively quickly, its relative advantage in terms of emissions as compared to coal and the relatively abundant supply of gas worldwide. The erosion of both the utilisation rates and profitability levels of gas-fired power plants impacts the business case of existing units. Although investment decisions are not just based on current prices but also on long term expectations, this erosion of profitability also dis-incentivises investments in new plants, which in turn increases long term generation adequacy concerns.

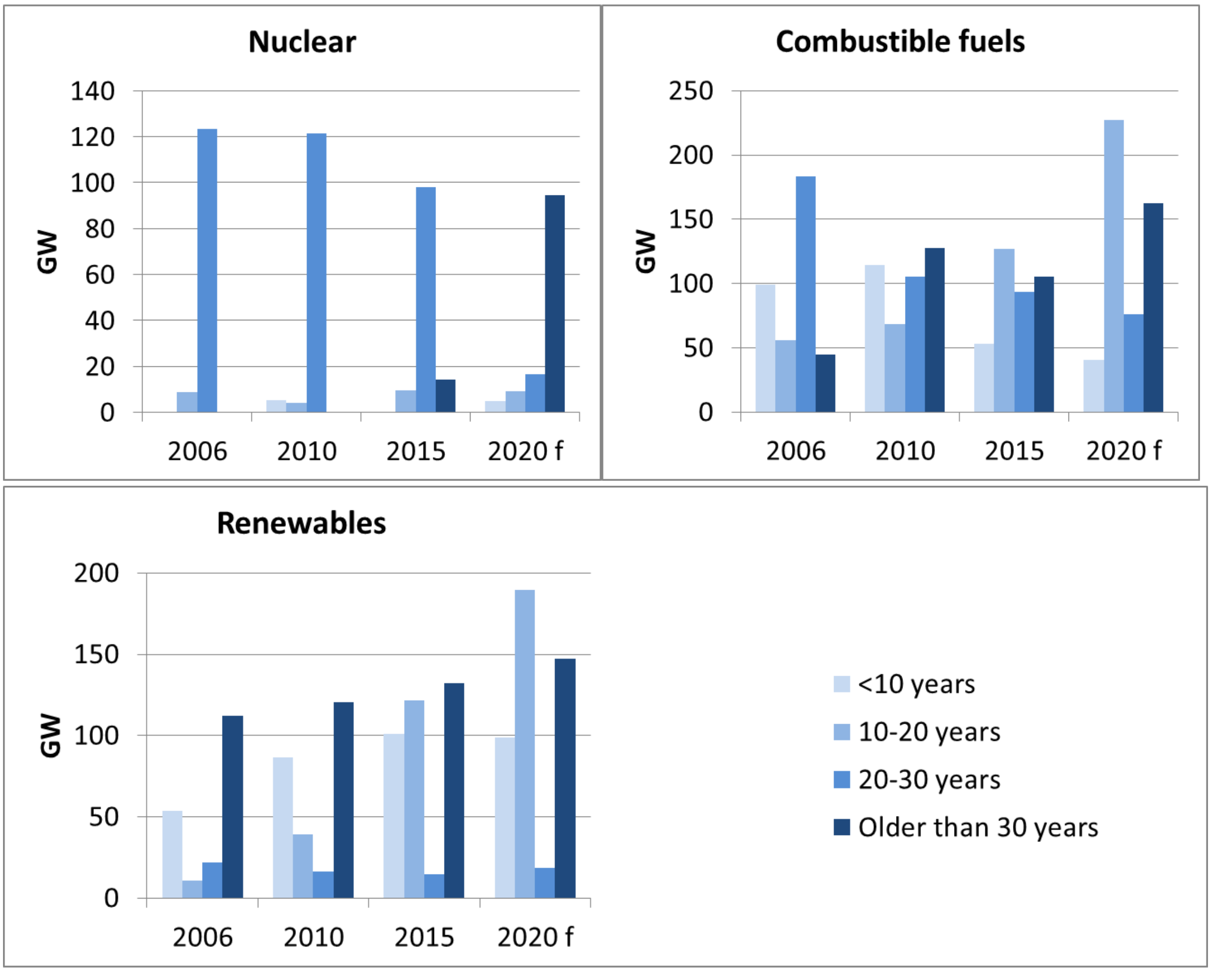
2.1.3.4 Ageing of coal and nuclear plants

A significant proportion of current installed generation capacity is approaching the limit of its operational life. Most nuclear plants have been in operation already for 20 to 30 years, and will be older than 30 years by 2020. In Europe, little investment in new nuclear plants is planned and a number of countries are phasing out their nuclear fleet. While investments are being made to extend the life of a number of nuclear plants, notably in France, a significant share of nuclear generation capacity may close in the coming decades.

Combustible fuel plants are more evenly distributed across age intervals, the oldest being mainly coal plants and the younger being mainly gas plants, especially combined cycle gas plants. Coal plants are candidates to be gradually phased out, not only due to their age, but also as a consequence of environmental policies.

Regarding renewables, most hydro plants are older than 30 years, but their operational life is not as limited as for nuclear and coal plants. They are expected to keep operating for many decades, provided the necessary maintenance investments are made. Wind and solar generation units are the youngest in the capacity generation mix, most of them having been operational for less than 20 years.

Figure 19: Distribution of age of power plants per type of generation



Source: Platts Power Vision

2.2 Incentives for future investment in generation

Declining demand and increasing shares of renewables resulted in decreasing profitability of electricity generators, especially conventional flexible technologies. The trend to more generation from renewables constitutes an economic challenge for the business model of many established energy companies with a fossil fuel-based generation park. While the shift towards more renewable energy production is, on the one hand, an intended development resulting from the decarbonisation of the generation fleet, it might pose a challenge to security of supply. Combined with the general ageing of power plants, the question of whether investments in generation capacity will be sufficient to guarantee an adequate generation fleet to meet future demand has gained prominence.

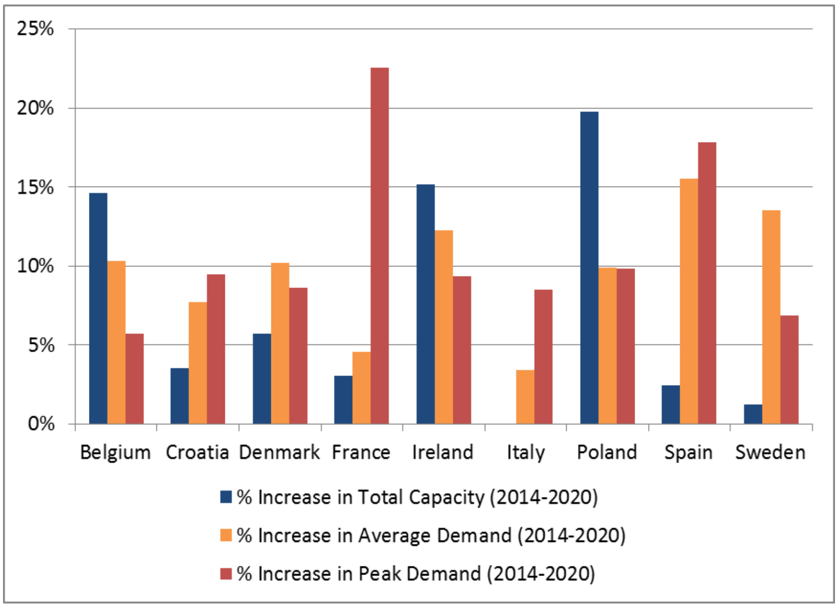
To the extent that low profitability reflects an excess of installed generation capacity, the resulting lower incentives to invest may be a sound economic signal to correct for overcapacity. However, if low profitability is the consequence of market and regulatory failures, then incentives to invest may prove insufficient to maintain adequate generation capacity in the medium and long term. It is therefore important to assess what drives investments in the European electricity markets of today and how that will influence the generation mix of the future.

This section presents the evidence obtained from the sector inquiry on the expectations of public bodies and market participants about future installed generation capacity and capacity margins, and discusses, on the basis of empirical evidence as well as economic literature on the subject, the market and regulatory failures that impact the incentives to invest in generation capacity.

2.2.1 Expectations about future development of generation and demand

The sector inquiry responses show that total projected installed capacity will increase at a slower pace than demand in six out of the nine Member States where data was available.

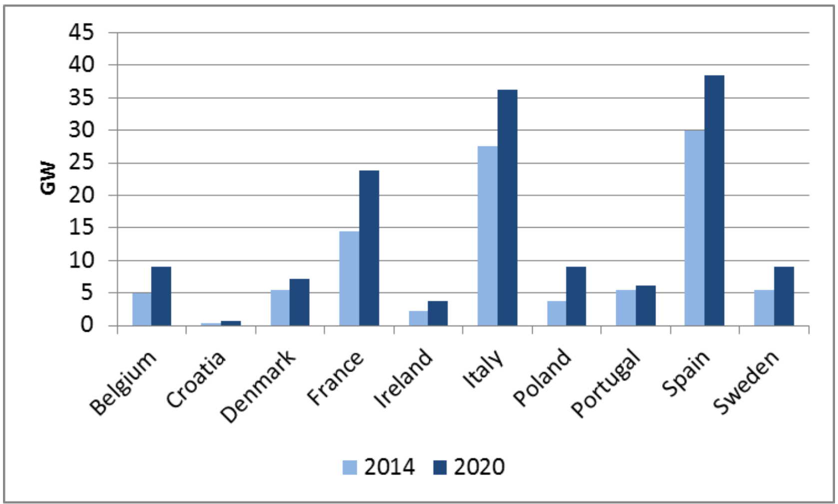
Figure 20: Evolution of projected installed capacity and demand by Member State



Source: European Commission based on replies to sector inquiry

In the Member States where this trend is reversed (Belgium, Ireland and Poland) the main contributor to the increase in projected installed capacity is the investment in renewable generation capacity.

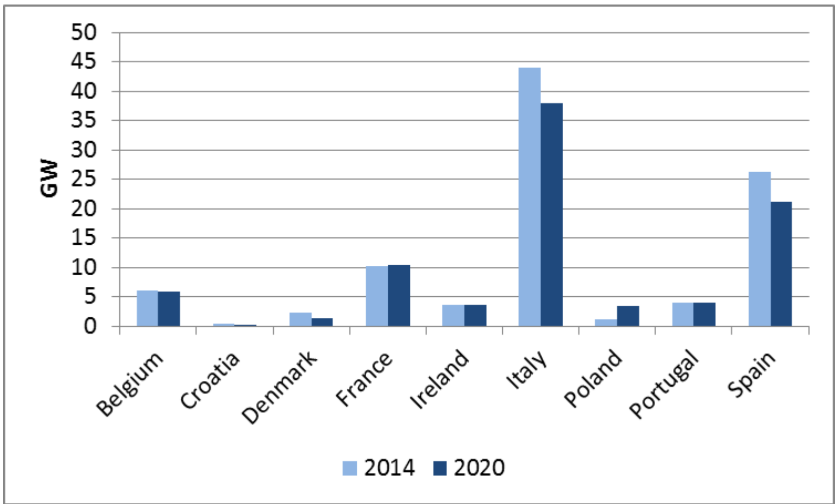
Figure 21: Current and projected installed wind and solar generation capacity in GW



Source: European Commission based on replies to sector inquiry

The responses also show that, despite significant investment in gas generation in recent years, expectations of future investments in gas generation are rather low; no Member State except Poland expects material increases in gas-fired generation capacity.

Figure 22: Current and projected installed gas-fired generation capacity in GW



Source: European Commission based on replies to sector inquiry

Several signals may have contributed to the negative perception regarding investments in gas-fired generation capacity. First, the growth in demand is expected to be modest, at least below pre-crisis levels. Second, lower coal prices and the fall in the ETS prices have had a clear positive impact on the profitability of coal-fired power plants at the expense of gas-fired competitors.

Lower profitability for flexible conventional technologies resulting from these developments has a negative impact on incentives to continue investing in these types of technologies. The increasing risk perceived by investors as a consequence of the reduction of operating hours during which these technologies expect to have to recoup costs and get appropriate remuneration further contributes to erode incentives to invest.

Incentives to invest shape the energy mix of the future and therefore determine the level of reliability that mix will provide. The relation between incentives to invest in generation capacity and the desired level of reliability is therefore the core challenge from a regulatory perspective.[20] In the context of the sector inquiry, 88% of public bodies that responded to the questionnaire expressed that no reliability problems had been observed in their Member States over the last 5 years, but 69% of them expected reliability problems to arise in their Member States in the future. This indicates that there are concerns among public bodies regarding future reliability.

It is therefore important to understand whether electricity markets provide sufficient incentives to invest whenever new investments into generation become necessary. The time dimension is a relevant factor, given the lead times between investment decisions and operability of the new generation capacity. Expectations about future market prices are therefore typically more determinative than current market prices and, in terms of ensuring generation adequacy at all times, an important question is whether investments are done timely. The remainder of this chapter explains what incentives electricity markets can be expected to provide and why they may be insufficient to guarantee adequate generation capacity and reliability in the future.

2.2.2 Market and regulatory failures undermining incentives to invest

As in any other sector, investment decisions crucially depend on the returns that private investors expect to obtain. In the case of electricity generation, either through revenues from electricity trading/sales or other channels (e.g. selling ancillary services[21], or participating in capacity mechanisms or renewables support schemes).

Electricity markets where generators obtain revenues only from selling electricity, balancing power[22] and providing ancillary services have been termed 'energy-only markets' in the economic literature. In such markets, generators take their decisions to invest in maintaining current capacity and installing new capacity on the basis of their expectations of future earnings obtained exclusively from these revenue streams. Hence, in an energy-only market, supply and demand for electricity determine the profitability of generation activities and the incentives to invest in future generation capacity.

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[20] As Cramton P., Ockenfels A. and Stoft S. (2013) explain it: "the heart of the adequacy problem is resolving the trade-off between more capacity and more blackouts."

[21] Directive 2009/72/EC defines ancillary service as: ‘a service necessary for the operation of a transmission or distribution system.' Examples of such services that TSOs can acquire from generators are electricity for the compensation of grid losses, regulating power and emergency power.

[22] To the extent that balancing power markets foresee remuneration based on availability in addition to delivery, they already embed some payment for capacity and thus cannot be considered purely energy-only markets in strict sense. However, such payments for availability are designed mainly to provide short-term balancing possibilities, rather than long-term generation adequacy. Moreover, these markets represent relatively low traded volumes relative to the overall level of capacity.

Current liberalised electricity markets in the EU are imperfect examples of energy-only markets, given that in most Member States some or all generators obtain revenues through channels other than market prices, for instance in the form of subsidies and payments that affect their incentives to invest in generation capacity.

The economic literature has extensively discussed whether different models of electricity wholesale markets can be expected to generate sufficient incentives to invest to guarantee adequate generation capacity. When this is not the case, a so-called 'missing-money' problem arises: the market proves unable to incentivise investment in adequate generation capacity because investors fear future revenues will not cover their fixed costs and will not appropriately remunerate their investment.[23]

The missing-money problem is mainly related to the potential inability of electricity markets to deliver sufficiently high prices during periods of scarcity – as explained in the next Section – although other factors have been discussed in the economic literature that can also contribute to the lack of incentives to invest, such as the public good features of system reliability and the uncertainty about expected returns on investments in generation capacity.

2.2.2.1 Factors undermining price signals in electricity markets

Prices in competitive electricity markets reflect to a large extent the operating costs of the generation plants that are activated to serve the demand for electricity. However, this is not always the case even in very competitive markets. In principle, wholesale prices in perfectly competitive electricity markets equal the marginal cost of the most expensive generation unit being utilised at every moment in time, provided that there is sufficient available supply to meet demand at such price. But this is not always the case because sometimes demand for electricity comes close to or may even exceed the total available generation capacity, leading to a situation of scarcity. In such circumstances, market prices typically rise above marginal cost to contract demand and allow the market to clear. These transitory prices above operating costs produce margins that remunerate the fixed costs of marginal generating units. An energy-only market relies to a large extent on the rents generated during periods of scarcity to provide sufficient incentives for generators to invest in capacity.[24]

The theoretical efficient functioning of this market design depends on a number of assumptions that are rarely satisfied in existing wholesale electricity markets, in particular that

[23] As Joskow P. L. (2013) puts it, "the revenue adequacy or missing money problem arises when the expected net revenues from sales of energy and ancillary services at market prices provide inadequate incentives for merchant investors in new generating capacity or equivalent demand-side resources to invest in sufficient new capacity to match administrative reliability criteria at the system and individual load serving entity levels."

[24] As Cervigni G. and Perekhodtsev D. (2013) explain, "pricing in conditions of scarcity is a crucial element of the wholesale electricity market's design. Since the available generation capacity is far greater than demand in most hours, the competitive market-clearing price very rarely departs from the system marginal cost. Therefore the generating units with the highest variable costs rely on the extremely high prices prevailing during very few hours of scarcity to cover their fixed costs."

the demand can respond to variations of wholesale prices in real time and that generators do not enjoy a significant degree of market power.

The demand for electricity is typically insufficiently responsive to prices because currently prevailing technical features of electricity delivery do not allow most customers to respond to price variations in real time. As a consequence, there may be situations when the wholesale energy market cannot clear, because demand remains above available generation capacity independently of the price level. In such circumstances, some kind of regulatory intervention is needed to bring supply and demand in balance, e.g. by rationing demand and administratively setting a price.

Economic theory indicates, under certain assumptions, that during periods of rationing it is optimal to set a price at the level of the value of lost load (hereafter, 'VOLL'). VOLL is equal to the marginal consumer surplus associated with a unit increase in electricity supplied to rationed consumers. In other words, it expresses the value attached by consumers to uninterrupted electricity supply. A regulated price at the level of VOLL when the market does not spontaneously clear would in theory provide incentives to invest in generation capacity that reflect consumers' average willingness to pay for security of supply.[25]

In most Member States price caps currently exist which are not based on estimates of average VOLL, but often on the technical bidding limits used by power exchanges. The maximum price may also be limited by the rules by which imbalance settlement is calculated, since market participants will never choose to pay more for electricity in the market than they would be charged for a deficit after gate closure. Although VOLL has not been calculated in many Member States, those Member States that have calculated it, report values that are well above their price caps in the day-ahead market.[26] Table 1 reports the price caps in each of the 11 Member States, as obtained from responses to the sector inquiry.

[25] As Cramton P., Ockenfels A. and Stoft S. (2013) explain: "The market responds to VOLL by building additional capacity up to the point where a MW of capacity costs just as much as it earns from being paid VOLL during blackouts. (…) So at this point the cost of capacity equals the value of capacity to consumers, and beyond this point, consumer value per MW can only decline as the system becomes more reliable. Hence, the VOLL pricing rule causes the market to build the second-best, 'optimal' amount of capacity. This solves the adequacy problem – with help from a regulator." A first-best solution can only be obtained by enabling a fully responsive demand-side allowing the market to clear at all times on the basis of individual consumers' preferences.

[26] See Chapter 5 on Adequacy Assessments for a discussion on the way in which VOLL is calculated. Where VOLL has been estimated by MSs it ranges from EUR 11,000/ MWh to EUR 26,000 / MWh, so significantly higher than existing European price caps.

Table 1: Price caps in the Day-Ahead Markets of the 11 Member States[27]

Wholesale Price Caps (EUR/MWh)	
Country	Day-ahead
Belgium	3,000
Denmark	3,000
Croatia	no cap
France	3,000
Germany	3,000
Ireland	1,000
Italy	3,000
Poland	no cap
Portugal	180
Spain	180
Sweden	3,000

Source: European Commission based on replies to sector inquiry

There are several reasons why in practice prices are often capped significantly below VOLL level. In practice it is a challenge to accurately estimate the VOLL to ensure that prices are set to incentivise investments in generation capacity up to a level that reflects consumer willingness to pay for additional security of supply.[28] Alternative emergency measures (like activating operating reserves, dispatching emergency demand response or implementing voltage reductions, for instance) are used to balance markets that suppress price signals, instead of implementing involuntary curtailments of demand and VOLL pricing.[29]

Moreover, when generators enjoy some degree of market power, they may abuse it by engaging in withholding capacity or strategic bidding to increase wholesale electricity prices to their benefit. The risk that generators implement such strategies is particularly high when the system approaches situations of scarcity, because in these circumstances virtually every generating unit becomes pivotal and enjoys some degree of market power.[30] The current lack of demand response to wholesale price variation further contributes to making the exercise of

[27] Note that in some markets the intraday price cap is higher than the cap indicated for the day-ahead market (for instance in countries where electricity can be traded at EPEX the technical price cap on the intraday market is EUR 10.000-.

[28] See Cramton P., Ockenfels A. and Stoft S. (2013).
[29] See Pfeifenberger J., Spees K. and DeLucia M. (2013).
[30] As Joskow P. L. (2008) explains: "Unfortunately, the supply and demand conditions which should lead to high spot market prices in a well-functioning competitive wholesale market (i.e. when there is true competitive 'scarcity') are also the conditions when market power problems are likely to be most severe (as capacity constraints are approached in the presence of inelastic demand, suppliers' unilateral incentives and ability to increase prices above competitive levels, perhaps by creating contrived scarcity, increase)."

market power more likely and profitable, because increases in prices do not trigger any significant reductions in the final demand for electricity.[31]

Regulators and competition authorities may find it difficult to distinguish instances of exercise of market power abuse and market manipulation from genuine scarcity conditions. In both cases the main observable market outcome is higher wholesale prices. Generators can for instance disguise withholding of capacity as technical maintenance or failure. It is not easy either to assess whether generators bidding above their running costs are legitimately seeking to cover their fixed costs, or are seeking to make windfall profits thanks to the lack of demand response.

A number of market-power mitigation measures have been applied in wholesale electricity markets – apart from permanent scrutiny by competition authorities and the increased monitoring of electricity trading under the REMIT Regulation[32] – including forced capacity divestitures, long-term contracts, virtual power plants[33] and price caps. The latter two are more likely to create or contribute to a missing money problem because they are based on constraining the ability of prices to increase in periods of scarcity.[34] Especially price caps close to the marginal operating cost of the last generation unit in the merit order curve can be effective at mitigating concerns about anticompetitive behaviour, but they are also likely to create or exacerbate the 'missing money' problem by curbing scarcity rents earned by generators.

Moreover, allowing prices to rise to VOLL in periods of scarcity is likely to entail very high wholesale prices, albeit during short periods of time. Concerns have been raised that such high prices may be politically or socially difficult to accept where there is a perception that relying exclusively on scarcity pricing entails higher risks (for instance, spilling over to retail markets) than alternative measures based on remunerating capacity through out-of-the market channels.[35] However, experience in several countries showed that wholesale market participants may be able to hedge against short-term price peaks, with limited additional costs for end consumers.

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[31] As Spees K. and Lave L. B. (2007) explain referring to some past experiences in US markets: "A serious problem with the deregulated market structure is that the system operator creates an auction market where demand is completely unresponsive to price and all successful generators are paid the market price; this market design offers an all but irresistible temptation for generators to manipulate the market, sending prices soaring, as happened in California in 2000."

[32] Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency

[33] Under a virtual power plant or VPP scheme the incumbent party is obliged to sell some of his generation capacity to third party market participants (e.g. new entrants). The buyer of the VPP contract has the option to consume power of his VPP against the agreed virtual production cost, but not the obligation and hence the contract can be seen as a call option. VPPs have been imposed by competition authorities in Europe both as a remedy in merger cases and to address dominance.

[34] For a more in-depth discussion of the various market-power mitigation measures see Cervigni G. and Perekhodtsev D. (2013).

[35] As Besser J. G., Farr J. G. and Tierney S. F. (2002) claim: "In theory, energy and ancillary service markets alone can provide incentives for investment in electricity supplies. However, they can only do this by subjecting consumers to price volatility, price levels, supply shortages, and a level of risk to reliability that costumers and policymakers would find unacceptable."

2.2.2.2 Uncertainty on returns increases risk premiums required by investors

Generators' expectations about future returns on their investments in generation capacity are affected not only by the expected level of electricity prices, but also by several other sources of uncertainty, such as increasing price volatility, recurrent regulatory reforms and the uncoordinated decisions of competitors.

The increasing weight of intermittent renewable technologies makes prices more volatile and shortens the periods of operation during which conventional technologies are able to recoup their fixed costs.[36] In such circumstances, even slight variations in the level, frequency and duration of scarcity prices have a significant impact on the expected returns on investments, increasing the risk associated to investing in flexible conventional generation technologies.

Since the onset of the liberalisation of electricity markets, regulatory frameworks have gradually evolved over time, and are expected to continue to change to respond to the political objectives of decarbonisation, affordability and security of supply. Given the relatively long time periods over which investments in generation capacity are typically expected to be recouped, the lack of a stable regulatory framework adds uncertainty regarding the expected returns on investments in capacity.

Investment decisions in the electricity sector are typically taken long before returns on investment are effectively earned, due to the time needed to construct new power plants. At the same time, the decentralised nature of investment decision-making means that each generator has limited information about the generation capacity that competitors will made available in the coming years. This constitutes an incentive to delay investments until there is sufficient reassurance that additional generation capacity is actually demanded in the market.[37] This may be less problematic where generation with shorter planning and construction times is sufficient to ensure adequacy (for instance, small and highly flexible gas plants in certain areas), but may be more problematic where larger power plants with longer lead times of 10-15 years are required. The result is what has been referred to as boom-bust cycles: alternate periods of shortages and overcapacity resulting from lack of coordination in the investment decisions of competing generators.[38]

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[36] Cramton P. and Ockenfels A. (2012) note that "all these effects imply that the 'missing money' problem is becoming more severe as the renewables' share grows." In the same vein, Joskow P. L. (2013) considers that "the expansion of subsidized intermittent generation and other subsidized generating investments have exacerbated and complicated the problem."

[37] According to De Vries L. J. (2007), there "are reasons for generating companies to delay investments until the need for generation capacity becomes reasonably certain. (…) Depending on the growth rate of demand, investment in reaction to price rises may not arrive soon enough to prevent a significant period of shortages."

[38] Cramton P. and Ockenfels A. (2012) formulate this in the following terms: "In a pure-market design, the decisions to build new capacity are made independently. This induces strategic uncertainty: because one's investment in new capacity tends to be more profitable if others invest less, there are incentives to not or to misinform about one's own intentions. This seems partly reflected by the observation that there is typically a significant gap between the announced plans to build new plants and actually executed plans. (…) The optimal strategy implies a random element and so the outcome is likely to be inefficient."

Investors factor in all these sources of uncertainty when making their investment decisions. Different authors give different weight to each of these factors,[39] but they all contribute to increase risk for investors.[40] If investors demand larger risk premiums, energy-only markets may not be able to generate sufficient incentives to invest even with high scarcity prices.

2.2.2.3 Public good features of reliability lead to insufficient investment signals

The reliability of electricity systems has certain features of a public good. On the one hand, investments in capacity to increase the system's overall reliability to meet the preferences of the most demanding consumers also reduce everyone else's risk of supply interruption at no extra cost (in economic terms, this is the feature of 'no rivalry'). On the other hand, it is currently not possible for most individual final consumers to be selectively disconnected by the system operator on the basis of their individual VOLL (this is the feature of 'non excludability'). These two features are the ones that characterise a public good from an economic perspective.

This means that in events of scarcity each consumer's likelihood of being disconnected is independent of his VOLL, making him unwilling to pay for reliability as much as he would otherwise be willing to. Economic theory thus suggests that in such circumstances a decentralised competitive market is likely to provide suboptimal incentives for generators to invest in generation capacity, which would therefore ultimately deliver suboptimal levels of system reliability compared to what consumers would have been willing to pay for if they were able to be individually disconnected on the basis of their individual VOLL.[41]

2.2.3 Conclusions on the lack of optimal incentives to invest

European electricity markets suffer from a number of market and regulatory failures undermining investment incentives. Demand for electricity is largely inelastic due to technical factors and regulatory barriers, which implies lack of responsiveness of demand to price variation and leads to inefficient price signals. System operators use a variety of tools to force the market to clear in ways that supress market price signals. Price caps are often set below VOLL for various reasons. Uncertainty about expected future returns on investment in generation capacity contributes to undermine incentives to invest. As long as system reliability continues to have the features of a public good due to the current technical characteristics of electricity dispatching, decentralised markets may generate insufficient reliability levels.

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[39] Joskow P. L. (2008) for instance, notes that "large investments in production facilities whose output exhibits significant price volatility occur all the time (e.g. oil and natural gas)", but acknowledges the relevance of regulatory uncertainty "as policymakers have not been shy about ex-post adjustments in electricity market designs and residual regulatory mechanisms, sometimes by a desire to hold up existing generators opportunistically."

[40] As De Vries L. J. (2007) explains, "for generating companies, investing in excess of the socially optimal volume of generating capacity means that competitive prices will be too low to recover their investment, while a volume of generating capacity that is below the social optimum leads to significantly higher average prices, which offset the lost turnover at least partly."

[41] See Abbot M. (2001).

Electricity markets in the eleven Member States share most of these characteristics. It is therefore understandable that they pose the question whether the current structure of electricity markets may lead to problems of generation adequacy in the future, even though there may not exist such a problem today. Answering this question requires an in-depth assessment of the current situation of electricity markets, as well as of the expected evolution of both the demand and the supply sides in the coming years.

2.3 What is being done to alleviate imperfections of EU electricity markets?

Against the backdrop of reduced investment incentives and increased concerns about reliability levels in the future, Member States can on the one hand attempt to alleviate imperfections of the current markets and on the other consider intervening in the market by generating additional incentives to invest via separate payments that directly remunerate capacity. This section assesses the improvements that have been proposed and are being carried out on a national and European level to address the market and regulatory failures in today's electricity markets and assesses to which extent residual generation adequacy problems may exist that can be addressed by capacity mechanisms.

2.3.1 Improving the functioning of the electricity market

Both at national and European levels, efforts are underway to implement better market designs and regulation aimed at improving market functioning. There is general consensus that there exists room for improvement of the efficiency of electricity markets, most notably by enabling demand response, broadening supply-side participation and improving the efficiency of market outcomes, especially during scarcity events.

On the demand side, increased demand responsiveness can have important impacts for generation adequacy because it has the potential to flatten demand peaks and thus reduce the need for additional generation capacity to ensure adequacy. Its role will further increase with the shift towards generation from variable renewables, as coping with shorter time generation peaks and gaps will be more in the focus of the balancing concerns in many Member States. Demand response can be realised both for household and small industrial/commercial consumers – where smart meters are progressively being deployed[42] and aggregators[43] are facilitating participation in electricity markets – and for larger industrial consumers. Experience has shown that the potential to integrate significant volumes of demand response on short notice is highest for industrial customers. Industrial consumers are being increasingly

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[42] For instance, in 17 Member States the wide-scale deployment of smart metering devices is underway or planned and data from Member States show that 72% of European consumers are expected to have a smart electricity meter by 2020. Moreover, retail consumers can increasingly choose more flexible tariffs based on real-time prices. For instance, in Finland and Sweden retail consumers increasingly opt for dynamically priced electricity contracts saving 15% to 30% on their electricity bills. Source: Communication from the Commission, 'Delivering a New Deal for Energy Consumers' of 15 July 2015, COM(2015)339 final, page 3 – 5.

[43] Demand response aggregators typically enter into contracts with small consumers and sell the combined load reduction that these consumers can achieve together to the system operators, sharing the revenues with the participants.

incentivized to reduce load in times of scarcity by making them sensitive to wholesale prices, either directly responding to the real-time market signals or through commercial offerings from their suppliers. Smart grids and meters help mitigating the problems related to the public good character of reliability as they allow individual consumers to manage their consumption on the basis of price signals. Moreover, a manageable demand side provides an additional tool to TSOs in balancing the system, by providing balancing or ancillary services to the TSO or by participating in a targeted scheme for interruptible loads.

On the supply side, participation can be broadened to ensure that all potential contributors are able to deliver what they physically can to meet peak demand. Renewables for example have historically been shielded from price fluctuations in the market to help support the development of nascent technologies. However, now that RES generation is maturing and comprises a significant proportion of overall installed capacity, there is an increasing opportunity for a more active participation in the market. There is still a substantial number of Member States in which RES producers are either not able or have no incentive to participate in the wholesale market and react to price signals, for instance because they bear no responsibility to ensure that their actual generation output meets projections.

Table 2: Balancing Responsibility for RES in the eleven Member States

Balancing Responsibility for RES	
Country	Balancing responsibility
Belgium	Yes
Denmark	Yes
Croatia	No
France	No
Germany	FIP Only[44]
Ireland	Partly
Italy	Partly
Poland	Yes
Portugal	Yes
Spain	Yes
Sweden	Yes

Source: European Commission, adapted from Commission Communication 'Delivering the internal electricity market and making the most of public intervention', 5 November 2013, C(2013)7243

Another example is foreign capacity. The participation of foreign capacity is optimized in the day-ahead market where market coupling has been implemented, but regulatory arrangements typically do not allow use to be made of interconnection closer to real time when scarcity

[44] Balancing responsibility is only applied to those renewable generators that receive a feed-in premium and thus participate in the market (currently some 80% of RES).

would be expected to emerge.[45] Under market coupling rules, the only signal that is taken into account for determining cross border electricity flows is the electricity price, so it is important to ensure that electricity prices can rise to reflect consumers' willingness to pay.

Improving short term markets can make a considerable contribution to a more efficient balancing of supply and demand during the day. The increase of intermittent renewables has created more uncertainty in forward and day-ahead trading and more volume volatility during the day. It has therefore become more important to improve possibilities for balance responsible parties to balance their portfolios on the shorter term intraday and balancing markets. The closer to real time, the more accurate the forecasts of potential suppliers on what they will be able to generate and the better the TSO can estimate his needs in terms of balancing energy. Measures such as moving gate closure time[46] closer to real time or allowing shorter term products to be traded have been discussed as ways to facilitate the participation of additional amounts of capacity, contributing to more cost-efficient market functioning. Intraday and balancing markets can moreover be opened up for participation of generators from across the border.

Fuller participation in markets – on both the supply and the demand side – may not in itself be enough to ensure efficient short term signals for supply and demand, including across borders, nor long term signals for investment in the overall mix of capacity with the right flexibility and reliability characteristics needed to meet demand. In a well-functioning market, prices reflecting VOLL could provide reliable signals. However, as discussed in the previous section, estimation of VOLL can be a challenging task and allowing extremely high price peaks presents policy makers with other regulatory challenges, for instance because of the potential for abuse of market power. Measures designed to allow price spikes to occur, while ensuring these risks do not materialize, have been proposed. For instance, the introduction of hedging products which suppliers can buy to protect themselves against peaks. Options are widely traded in Australia – where price spikes are allowed – and are being introduced in Germany by EEX.[47]

Another element of market design that is crucial for ensuring efficient locational signals for investment in generation and transmission, and the location of demand, is a more efficient definition of bidding zones. The European market is divided into bidding zones within which

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[45] However, power exchanges have initiated pilot projects aimed at the development of cross-border intraday trading based on implicit continuous trading, in accordance with the Commission's Target Model for Intraday and Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a Guideline on Capacity Allocation and Congestion Management.

[46] The Gate Closure Time is the time at which a market closes and trading is no longer allowed. The closer Gate Closure Time is to real time (i.e. the time that the traded electricity is to be delivered) the better generators (especially wind and solar) are able to estimate the precise quantities they can produce and therefore the wider the participation on the short term markets.

[47] 'An electricity market for Germany’s energy transition', White Paper by the Federal Ministry for Economic Affairs and Energy, July 2015. Available at: http://www.bmwi.de/English/Redaktion/Pdf/weissbuch-englisch,property=pdf,bereich=bmwi2012,sprache=en,rwb=true.pdf

See also: https://www.eex.com/en/about/newsroom/news-detail/eex--successful-start-of-trading-in-cap-futures/91972 market participants can trade electricity without having to acquire the rights to use transmission capacity. As such, the price formed in each zone reflects the overall demand/supply balance in the zone.

Ideally, for electricity prices to appropriately signal local scarcity the market area or bidding zone needs to reflect the technical limits of the transmission system. The price in a very large zone may not indicate with sufficient precision where additional generation capacity is most needed and transmission constraints may cause inefficient plants to run instead of more efficient ones. In such situations, TSOs are forced to revert to re-dispatching measures[48] in order to ensure system balance and minimize loop flows, leading to significant costs for consumers and possible market distortions.[49] Zones defined based on transmission constraints can allow zonal electricity prices to provide more accurate signals for the efficient location of generation capacity and electricity demand. Of the Member States assessed in the context of the sector inquiry, Denmark, Italy and Sweden have divided their electricity market in two or more bidding zones.

Finally, though reforms are necessary to improve market functioning, the extent to which an electricity market delivers signals for sufficient investment depends on investors' view of long term regulatory stability. Regulatory stability helps create an environment in which longer term and forward trading can happen within the market, which can provide an important basis for supporting new projects. Alongside a stable regulatory framework for electricity prices, the longer term impact of carbon prices is an important consideration for investors, and a reformed European carbon market with a functioning Market Stability Reserve that addresses the surplus of emission allowances on the market will help to deliver this.

2.3.2 Addressing residual market failures with a capacity mechanism

The reforms mentioned in the previous section could significantly improve the efficiency of electricity markets. Some analysts indicate that there is practical evidence that an energy only market design can realise sufficient investment without the need for mechanisms that make separate capacity revenues available to generators and/or demand response.[50] However, other

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[48] A TSO that applies re-dispatching requests or instructs a power plant to adjust their power generation in order to address congestions and maintain system balance.

[49] Deviations between scheduled flows and physical flows are defined as unscheduled flows. Loop flows are generally defined as those unscheduled flows that are caused by scheduled flows within a neighbouring bidding zone. ACER has undertaken extensive research into the occurrence of loop flows and the negative impacts they have on cross border flows, trade and social welfare in its Market Monitoring Report 2015: http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER_Market_Monitoring_Report_2015.pdf

[50] The electricity markets of Australia and Texas are often referred to as examples of functioning energy-only markets. In Australia, the price cap is set at VOLL, but market participants have ensured themselves against peaks by developing hedging products which in turn allow operators of peak generation units to earn a stable income in the energy-only market. In Texas, the electricity price is amplified by adding a pre-defined amount of money per MWh to the electricity price depending on the stress of the system. The lower the remaining reserves, the higher the sum that is disbursed to the contributing generators. According to the respective regulatory authorities, both of these markets appear to have delivered sufficient investment to meet centrally determined reliability standards over many years. See for Australia:

authors stress that such reforms alone may not completely solve the missing-money problem.[51]

Either because market reforms may take time to be fully implemented or because they may be insufficient to fully address the generation adequacy problem generated by the lack of optimal incentives to invest in generation capacity, Member States may want to establish additional measures to address a residual missing money problem and ensure generation adequacy.[52]

The eleven Member States under assessment in this inquiry have opted for the introduction of one or more capacity mechanisms to address perceived residual market failures. The designs of the mechanisms vary widely, but all have in common the underlying principle of enabling revenues for capacity providers and thus they may fall within the category of state aid measures. They can therefore be subject to the Union's rules on state aid and their compatibility with these rules may have to be assessed by the Commission.

The following chapters describe and assess the capacity mechanisms applied or planned in the eleven Member States.

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https://www.aer.gov.au/system/files/State%20of%20the%20energy%20market%202014%20-%20Chapter%201%20%20National%20electricity%20market%20A4_0.pdf and for Texas: Brattle Group's 1 June 2012 report to the Public Utility Commission of Texas, "ERCOT Investment Incentives and Resource Adequacy".

[51] See Joskow P. L. (2008): "The reforms to wholesale energy markets discussed above should help to reduce the missing money problem associated with the operation of many 'energy only' wholesale markets today. However it is not at all obvious that the missing money problem will be completely solved with these reforms or that they can be implemented overnight. These reforms may also increase market power problems and further increase price volatility."

[52] See Joskow P. L. (2008): 'Lessons learned from Electricity Market Liberalization': "A number of countries are considering imposing resource adequacy, forward contracting obligations, or providing capacity payments to generators to overcome imperfections in wholesale and retail markets in order to restore incentives for investments in generating capacity and demand response capabilities consistent with traditional reliability levels."

3. Member State interventions: overview and classification

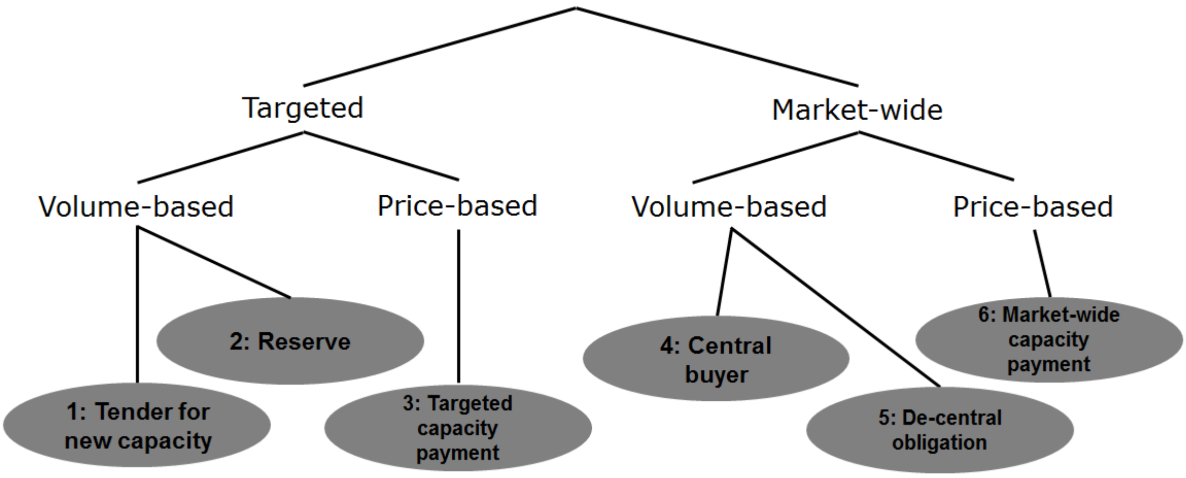
There are various types of capacity mechanisms. They can be categorised to some extent based on their basic characteristics, and within each category further parameters can be set that determine the precise design.[53] This chapter describes the six basic types of capacity mechanism previously identified by the Commission, and identifies where the capacity mechanisms identified in the sector inquiry fit into this framework.

The chapter briefly describes the main features of the different types of capacity mechanisms identified in the sector inquiry. More detail on specific design elements is provided in Chapter 5.

3.1 Types of capacity mechanisms

The various types of capacity mechanisms can be grouped into two broad categories: targeted mechanisms and market-wide mechanisms. Within these two categories, it is also possible to distinguish volume-based mechanisms and price-based mechanisms.

Figure 23: Taxonomy of capacity mechanism models



Source: European Commission

3.1.1 Targeted mechanisms

Targeted mechanisms are those where the amount of capacity required and the amount expected to be brought forward by the market are identified centrally. The capacity mechanism then provides support only to the additional capacity (or 'top up') expected to be needed beyond what would anyway be brought forward by the market.

[53] The Commission developed this categorisation in a Non Paper, which was discussed with Member States in a working group that took place on 30 June 2105. It is available here: http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_10_en.pdf.

For the purposes of the sector inquiry, we have identified three basic types of targeted mechanism.[54]

- Tender for new capacity – typically, the beneficiary of such a tender receives financing for the construction of a power plant that would bring forward the identified top up capacity. Once the plant is operational, in some models the top up capacity runs in the market as normal (without a guarantee that the electricity will be sold). It would also be possible for the plant to be supported through a power purchase agreement.
- Strategic reserve – in a strategic reserve mechanism, the top up capacity is contracted and then held in reserve outside the market. It is only run when specific conditions are met (for instance, when there is no more capacity available or electricity prices reach a certain level). Typically strategic reserves aim to keep existing capacity available to the system.
- Targeted capacity payment – in this model, a central body sets the price of capacity. This price is then paid to a subset of capacity operating in the market, for example only to a particular technology, or only to capacity providers that meet specific criteria.

Both the strategic reserve and the tender models are 'volume-based' mechanisms because the volume of capacity that receives support is determined at the outset. They differ from the 'price based' targeted payment model where there is no restriction on the amount of capacity that receives the payment, but rather a restriction on the type/s of capacity eligible.

3.1.2 Market-wide mechanisms

In a market-wide mechanism, all capacity required to ensure security of supply receives payment, including both existing and new providers of capacity. This essentially establishes 'capacity' as a product separate from 'electricity'.

There are three basic types:

- Central buyer – where the total amount of required capacity is set centrally, and then procured through a central bidding process in which potential capacity providers compete so that the market determines the price.
- De-central obligation – where an obligation is placed on electricity suppliers / retailers to contract with capacity providers to secure the total capacity they need to meet their consumers' demand. The difference compared to the central buyer model is that there is no central bidding process, but market forces should still establish the price for the required capacity volume.
- Market-wide capacity payment – where the price of capacity is set centrally, based on central estimates of the level of capacity payment needed to bring forward sufficient total capacity and then paid to all capacity providers in the market.

[54] http://europa.eu/rapid/press-release_MEMO-15-4892_en.htm

These mechanisms provide support to all (or at least the majority of capacity providers in the market – there may still be some restrictions on eligibility).

The central buyer and de-central obligation models are volume-based: in these models the volume of capacity required is set at the outset, while the price is determined by the market. The market-wide capacity payment is price-based since the price for capacity expected to achieve sufficient investment is fixed at the outset, while the volume may vary depending on how the market reacts to that price.[55]

Further variations are possible within the different models depending on the detailed design.

3.2 Capacity mechanisms in place in the 11 Member States

The Member States assessed in the sector inquiry have been selected because they have either introduced or are considering introducing one or more capacity mechanisms. The combination of Member States was also chosen to constitute a representative sample of the different capacity mechanism types being developed in Europe.

The mechanisms brought to the attention of the Commission by respondents to the sector inquiry vary widely and categorising them according to the taxonomy provided in Figure 23 is not always straightforward.

To help determine whether a measure or practice in a Member State qualifies as a capacity mechanism within the scope of this inquiry, the Commission has identified the following indicators. Capacity mechanisms:

- are generally initiated by or with the involvement of governments;
- have the primary objective of contributing to security of supply; and
- provide remuneration to capacity providers in addition to revenues they receive in the electricity market, or instead of revenues they could otherwise have received in the electricity market.

A particular area in which there may be debate about what constitutes a capacity mechanism is in the specification and procurement of ancillary services. TSOs typically procure these services to ensure the moment to moment balancing of the system. In some circumstances, these services appear to be procured independently and competitively by TSOs, are used in small volumes relative to the overall level of capacity in the market and are used only to provide short term corrections to enable system security. However, where ancillary services appear to be contracted at the request of governments and/or are used to ensure capacity is available to balance the system over longer periods, they can have the same effect as capacity

[55] Note even volume based mechanisms may be designed to enable some flexibility on the volume procured in reaction to prices of capacity (sloping demand curve), which is not known definitively until the allocation process takes place. This is for example the case in the planned Italian central buyer mechanism and in the GB capacity auction.

mechanisms. Such measures may merit attention from the Commission and require state aid approval.

In some cases capacity mechanisms do not cover the whole territory of a Member State. In particular islands may be excluded from a capacity mechanism (as is the case in one Portuguese scheme) or may benefit from specific support measures (for example, Italy has implemented separate interruptibility schemes, one for the mainland and one for Sardinia and Sicily).

Some mechanisms are hybrid forms of two types identified in the taxonomy: for example a Portuguese scheme which makes administratively determined payments to demand response beneficiaries, in return for their being available – effectively in reserve – until the TSO asks them to reduce demand. This has elements of the targeted capacity payment model (administratively determined payments to a subset of capacity providers) and of the strategic reserve model (beneficiaries are held in reserve and instructed to run by the TSO).

The sector inquiry identified six countries that operate specific schemes for demand response (usually large industrial users) that at first sight match the indicators for identifying a capacity mechanism: Germany, Ireland, Italy Poland, Portugal and Spain. Beneficiaries of such 'interruptibility schemes' are then held in reserve until required by the TSO. For this reason, these schemes can be regarded as a form of strategic reserve.

Other measures identified by respondents have some features of a capacity mechanism, but are not designed primarily to ensure security of supply and instead address other objectives, for example the existing Danish schemes for combined heat-power (CHP) generation which make payments for availability but were designed primarily to bring forward investment in CHP capacity and reduce emissions.[56]

Croatia was selected for assessment under the inquiry because the Croatian authorities notified a tender for new capacity launched by the State owned electricity company. However, discussions between the Commission and Croatian authorities are ongoing on whether this measure should indeed be considered a State backed capacity mechanism. For the purpose of the present inquiry, this measure is therefore not further considered as an example of a capacity mechanism.

Although not a definitive view of the number of capacity mechanisms in the countries covered by the sector inquiry, Table 3 below was compiled on the basis of responses to the sector inquiry and the above indicators and considerations, and gives an impression of the number and type of the capacity mechanisms in place or considered in the countries.

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[56] Denmark's support to CHP capacity has been the subject of previous State aid decisions – see SA.30382, SA.35486, and SA.42519.

Table 3: Capacity mechanisms in the sector inquiry

Tender for new capacity	Strategic reserve	Targeted capacity payment
Belgium **	Belgium	Italy
France	Denmark **	Poland
Ireland **	Germany ***	Portugal ***
	Poland	Spain ***
	Sweden	
	Germany (Interruptibility Scheme)	
	Ireland (Interruptibility Scheme)	
	Italy (Interruptibility Scheme) ***	
	Poland (Interruptibility Scheme)	
	Portugal (Interruptibility Scheme)	
	Spain (Interruptibility Scheme)	
Central buyer	**De-central obligation**	**Market-wide cap. payment**
Ireland *	France *	Ireland
Italy *		

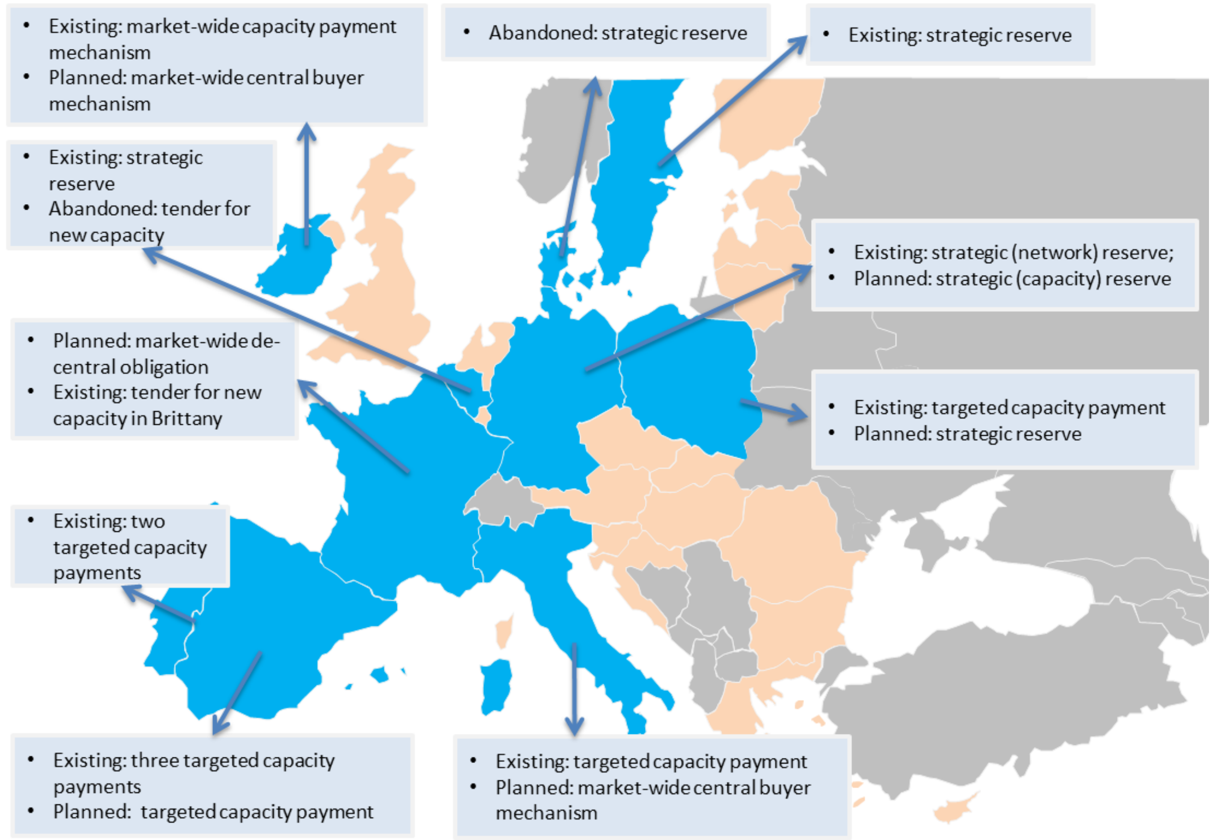
* Planned Mechanism (or being implemented)

** Past Mechanism (or never implemented)

*** Multiple capacity mechanisms of the same type

Source: European Commission based on replies to sector inquiry

Figure 24: Capacity mechanisms in the 11 Member States – excluding interruptibility schemes



Source: European Commission based on replies to sector inquiry

The following sections in this chapter describe the features of each type of capacity mechanism with reference to the examples found in the inquiry. The different schemes are described in terms of three general design elements:

- the eligibility rules, which determine any restrictions or requirements relating to the type, size and location of potential beneficiaries;
- the allocation process, which determines the way in which eligible beneficiaries are selected, and the way in which the capacity remuneration they will receive is determined; and
- the capacity product, which determines what the beneficiaries must do in return for their capacity remuneration, and what the sanctions are if they do not do this.

A more detailed analysis of these design elements is given in Chapter 5.

3.2.1 Tender for new capacity

Examples of tenders for new capacity were found in three of the Member States included in the sector inquiry: Belgium, France, and Ireland.

- Belgium in 2014 launched a tender to attract investment in 700-900 MW of OCGT (open-cycle gas turbine) or CCGT (combined-cycle gas turbine) capacity. The tender was however abandoned in early 2015.
- France launched a tender for the construction of a 450 MW combined cycle gas-fired power station in 2011 to deal with regional security of supply concerns in Brittany.[57]
- In 2003, Ireland developed a tender mechanism in view of an expected shortfall in capacity from 2005 onwards. The process resulted in the construction, in 2005 and 2006 respectively, of a new CHP facility and a new CCGT with a combined installed capacity of over 500 MW.[58]

3.2.1.1 Eligibility

All three tenders for new capacity specified many characteristics of the chosen capacity product in advance, including for example the size, technology type and location. The tenders in France and Belgium were limited to gas-fired plants only (with the tender in France limited only to CCGT capacity). The tender in Ireland was open to bids from any new centrally dispatchable thermal plants[59]. None of the three tenders were open to demand response.

[57] The Commission opened a formal investigation into the measure on 13 November 2015. See: http://europa.eu/rapid/press-release_IP-15-6077_en.htm

[58] The mechanism received state aid clearance from the Commission in 2003. http://ec.europa.eu/competition/state_aid/cases/137628/137628_485545_28_2.pdf

[59] Centrally dispatchable plants are those that can be dispatched at the request of power grid operators (ie. they can reliably begin generating on request).

All tenders were limited to new projects, although the Belgian tender was eventually opened to existing foreign capacity with the potential to be incorporated into the Belgian bidding zone. In all examples long contracts were available (ten years in Ireland, twenty years in France and up to seven years in Belgium).

In France, the proposed tender required a single bidder to fulfil the identified capacity requirement. In Ireland, the 2003 tender was open to multiple projects (of minimum 50 MW each) and in fact there were 2 successful beneficiaries that, taken together, were able to fulfil the identified requirement.

The French tender for new capacity was limited to capacity physically located in Brittany. The Belgian and Irish tenders were open to projects located outside of the Member States' national territory, but only on the condition that they had dedicated transmission connections to the Belgian or Irish grid.

3.2.1.2 Allocation process

In all of the tenders the price, but also the speed of development of potential projects were considered. In Ireland, bid prices were adjusted to account for the projects' locations and development dates; eventually the cheapest bundle of bids that met the requirement was selected. In the French and Belgian tender price was not the only award criterion; for instance, in both procedures the construction time was also taken into account. The French authorities also considered the proposed site of the installation and its impact on the environment, while in the Belgian tender procedure the "contribution to market functioning" (i.e. the contribution to a competition in the market, with a bias in favour of new entry) were also considered.

3.2.1.3 Capacity product

In Belgium and France, the successful beneficiary would receive capacity payments in return for making capacity available, and could participate in the electricity market and earn separate revenue from the sale of electricity. In France, these payments can be reduced both in case of non-availability and in case of a delay in the construction of the installation. In Belgium the selected power plant(s) would have needed to be available during winter for a predetermined amount of time, while in Brittany the availability obligations apply throughout the year.

In Ireland, the successful generators received 'capacity and differences agreements'. They received capacity payments for their availability, and were free to run in the market and earn separate electricity revenues. However, the agreements included a claw-back mechanism since the generators had to repay the difference if market prices went above a pre-defined strike price.

3.2.2 Strategic reserve

Examples of strategic reserves (excluding interruptibility schemes) were found in five of the Member States included in the sector inquiry: Belgium, Denmark, Germany, Poland, and Sweden. Germany plans to operate more than one strategic reserve.

- In Belgium a strategic reserve was introduced in 2014 as a back-up for peaks in demand during the winter period. 800 MW capacity was sought in the first year, increasing to 3,500 MW for the second year.
- Denmark proposed to create a new 200 MW strategic reserve in its Eastern DK2 bidding zone in 2016. The reserve was intended to be transitional until interconnection capacity is increased. However, the measure has not been implemented.
- Germany has a 'network reserve' in place to address grid bottlenecks between generation in the north of the country and demand in the south. The reserve consists primarily of power plants that have signalled their intention to close down but have been prohibited from doing so because they are deemed of importance for maintaining system stability ('system relevance'). These plants are moved into the network reserve, activated when there is insufficient network capacity to send power from north to south ('mandatory part') and reimbursed for the costs that result from the statutory interference with the rights of the plant operator. In case the combined capacity of the power plants that have been prohibited from closing is insufficient to satisfy the identified need for the network reserve, then a tender is organised to attract additional reserve capacity (the 'voluntary part'). In practice, this additional need is satisfied by power plants located in Austria and Italy. The network reserve differs from other strategic reserves not only because of its regional nature, but also because its activation is not triggered by a non-clearing market, but rather as an instrument for the TSOs in Southern Germany that allows them to maintain grid stability when there is insufficient transmission capacity to flow power to the south of the country ('re-dispatch'). A review of the network reserve is currently ongoing.
- Germany is also considering introducing a country-wide strategic reserve of 4.4 GW ('capacity reserve') as of October 2017, to be held outside the market. The deployment of the capacity reserve is triggered when the day-ahead or intraday market does not clear and if no other measures are available to the TSO, so as to minimise market distortions.
- Poland has created a strategic reserve comprising 830 MW of generation capacity ('cold contingency reserve'). The cold contingency reserve is intended to be transitional for two years starting in 2016, with the possibility to extend for a further two years beyond this.
- Sweden has operated a strategic reserve of up to 2 GW since 2003, designed to ensure sufficient capacity is available in the winter to cover peak load. The reserve currently comprises 1 GW capacity. The reserve was due to be removed after winter 2019/20 but market participant respondents to the sector inquiry have noted that Sweden plans to extend the strategic reserve for a further five years until 2025.

3.2.2.1 Eligibility

The technological eligibility rules for strategic reserves are varied, with the reserves in Belgium, Denmark and Sweden open to demand response as well as generation, while the German network reserve and the Polish reserve are only open to generation capacity. Reserves are typically not designed to attract new generation capacity.

Some reserves are location-specific, meaning they aim to address grid congestion or capacity shortage only in certain parts of a Member State. None of the strategic reserves are open to generators located outside of the Member State operating the reserve, except for the German network reserve.

3.2.2.2 Allocation process

In general, the strategic reserves include a competitive process for identifying the capacity providers that will provide reserve services, and in all examples with competitive processes beneficiaries are paid the price they bid for the services they provide (which usually includes a payment for being available and a separate activation payment). In practice, however, there is not always enough existing capacity on offer to allow for a competitive tender.

3.2.2.3 Capacity product

In all examples of strategic reserves except for foreign plants participating in the German network reserve, selected capacity providers are held in reserve outside of the market. They can no longer earn revenues from the sale of electricity, and can only run when instructed to do so by the TSO. In practice most reserves are used infrequently[60], but the existing reserves are usually dispatched when the day-ahead electricity market does not clear.

If the capacity providers are not able to make themselves available or fail to deliver when tested or called by the TSO, then they generally face a risk of missing out on future availability payments, or having to return already received availability payments.

3.2.2.4 Dispatch rules and link with market pricing

In Belgium and Sweden reserve capacity is dispatched if the day-ahead market fails to clear and there would be involuntary unmet demand without the reserve capacity. Reserve capacity can also be triggered intraday in Belgium if the TSO anticipates scarcity that was not apparent at the day-ahead stage. And in Sweden, reserve participants can also be dispatched by the TSO after gate closure in the regulating power market if there are insufficient commercial bids to meet demand.

Once reserve capacity is dispatched it can have a significant impact on electricity market prices. In Sweden, in periods when the reserve is activated electricity prices are set by the highest commercial bid in the electricity market. In the Belgian reserve and the abandoned Danish reserve, however, for periods when the reserve is dispatched and its capacity is required to meet demand, electricity prices are set to a pre-determined high level (EUR 4,500/MWh in Belgium, and EUR 3,000/MWh in Denmark).

[60] For example, the Swedish strategic reserve has been activated eleven times between 2003 and 2015. In seven of the twelve years of operation it was not activated at all. The Belgian reserve has not yet been activated.

3.2.3 *Interruptibility schemes*

A subcategory of strategic reserves, interruptibility schemes were found in six of the Member States included in the sector inquiry: Germany, Italy, Ireland, Poland, Portugal, and Spain.

- Since 2010, Italy also has operated two interruptibility schemes: one for the two main islands (contracting 500 MW in each of Sardinia and Sicily) and another for the mainland contracting 3,300 MW.
- Between 2013 and 2016 German TSOs have organised monthly tenders for 3,000 MW of sheddable load provided by consumers larger than 50MW. The scheme is presently being revised.
- In September 2012, the Polish TSO launched a tender to attract demand response services. The first tender failed to attract any bids but four subsequent tenders between 2013 and 2015 resulted in 200 MW demand response capacity being contracted.
- Since 2011, Portugal has operated an interruptibility scheme. 1,392.7 MW of capacity was contracted under the scheme in 2014.
- Since 2007 Spain has operated an interruptibility scheme. 3 GW of capacity was contracted in 2015.
- In Ireland the Powersave scheme, operated by Eirgrid, is a voluntary scheme encouraging large and medium sized customers to reduce their demand when total system demand is close to available supply. With up to 50 MW of total demand reduction potential it is considerably smaller than the other schemes.

In most schemes, beneficiaries are paid a fixed price for each MW of demand response made available as well as a price for demand reductions actually made (energy delivered). In Poland and Ireland beneficiaries are only paid for energy delivered and receive no availability payment.

There is a difference between schemes that have been established by the TSO to provide it with a valuable tool for ensuring system stability and schemes that have been introduced by the government to request a fixed amount of demand response to be contracted. Also where the capacity is requested by the government it may have a useful function, but the distinction is relevant from a state aid perspective. For instance, the interruptible load scheme established by the German government may be used by the TSOs for re-dispatch purposes. By temporarily switching off loads in the South, the need for north-south flows is alleviated.

3.2.3.1 Eligibility

By definition the interruptibility schemes are limited to demand response capacity. Some schemes have further restrictions on eligibility, such as minimum size requirements.

None of the interruptibility schemes are open to beneficiaries located in other Member States.

3.2.3.2 Allocation

All schemes allocate contracts through a competitive process, except Portugal and Ireland which set prices administratively. In Germany, currently demand for the service generally outweighs supply so prices are set administratively. Amendments to the scheme may address this issue by reducing the total demand.

3.2.3.3 Capacity product

In all schemes, large energy users must agree to be automatically disconnected when needed by the TSO. There is generally no prior notice and disconnection is often instant. Interruptions can last for up to several hours.

There are schemes where the product specification allows the TSO to respond to immediate balancing issues, such as frequency restoration, whereby it immediately remotely disconnects contracted loads, such as the German and Italian schemes. There are also schemes aimed at alleviating adequacy concerns of a longer term, such as the Irish scheme in which consumers are obliged to reduce their loads themselves upon notification by the TSO at least 30 minutes before the 'Powersave' event starts. Beneficiaries in the Irish scheme do not have to reduce their consumption, but are only rewarded if they do reduce their demand.

3.2.4 Targeted capacity payments

Examples of targeted capacity payments were found in four of the Member States included in the sector inquiry: Italy, Poland, Portugal, and Spain. Portugal operates two of these mechanisms, and Spain has operated four of these mechanisms.

- In 2003, Italy introduced targeted capacity payments for dispatchable generators. The mechanism was conceived as a transitional measure and Italy is planning to replace it with a central buyer mechanism.
- Poland has operated an operational capacity reserve since 1 January 2014. All available capacity that is not selected by the TSO to operate in the market (Poland has a central dispatch model) automatically constitutes the operational reserve and receives a fixed level of remuneration per MW and a payment per MWh if dispatched.
- Portugal operates two targeted capacity payments schemes:
    - an 'availability incentive' scheme that remunerates thermal plants for their availability; and
    - an 'investment incentive' scheme which aims to incentivise investments in new hydro generation and in the repowering of existing pump storage units through a capacity payment[61].
- Spain operates three targeted capacity payments schemes:
    - an 'investment incentive' scheme since 1997 for new nuclear, gas, coal, hydro, and oil plants;

[61] Pump storage units are hydropower facilities in which water can be raised by means of pumps and stored to be used for the later generation of electricity.

    - an 'availability incentive' scheme since 1997 for new and existing gas, coal, oil and hydro with storage; and
    - an 'environmental incentive' scheme since 2007 for coal plants that fitted sulphur dioxide filters.
- Between 2010 and 2014, Spain also operated a 'supply guarantee constraints resolution' mechanism which supported domestic coal production by providing plants burning domestic coal with priority dispatch[62] and regulated prices. Market participant respondents have noted that Spain may develop a new support scheme for plants burning domestic coal.

3.2.4.1 Eligibility

Most of the targeted capacity payments schemes are open to dispatchable generation (coal, gas, hydro with storage, and sometimes oil). But there are many variations, for example the hydro-specific investment incentive scheme in Portugal, the investment incentive in Spain which is also open to nuclear, and the environmental incentive in Spain which is only open to coal plants.

Although they are all national schemes and therefore geographically restricted to the territory of the Member State implementing them, most of the targeted capacity payments are otherwise non location-specific.

None of the targeted capacity payments schemes are open to demand response, nor are they open to beneficiaries located outside of the Member States operating the schemes.

Most targeted capacity payments schemes are open to existing and new generators and provide annual capacity payments with no longer term contracts.

3.2.4.2 Allocation process

By definition, capacity payments mechanisms involve an administrative price-setting and allocation process rather than a competitive price-setting process. The level of remuneration is set centrally – e.g. in Italy by the regulator – and then paid to all eligible capacity providers.

3.2.4.3 Capacity product

In general, the beneficiaries of targeted capacity payments must make their capacity available during peak demand periods, or face penalties requiring them to repay or forego capacity remuneration. However, beneficiaries of the Spanish investment incentive are simply obliged to build and operate an eligible power plant with no additional performance requirements.

[62] Plants subject to priority dispatch will be selected to generate electricity ahead of plants with lower running costs that would otherwise have been chosen to meet demand.

3.2.5 *Central buyer*

Examples of central buyer schemes were found in two of the Member States included in the sector inquiry: Ireland and Italy. Both mechanisms are still in development and are not yet operational. Examples of central buyer schemes are also found in the UK (British mechanism)[63], and in the United States including in the ISO New England and PJM systems on the East Coast.[64]

- Ireland intends to replace the existing market wide capacity payment mechanism in 2017 with a market-wide central buyer capacity mechanism based on reliability options.
- Italy is planning to replace its existing targeted capacity mechanism with a central buyer mechanism, where reliability options would be traded in auctions organised by the TSO. Italy plans to implement the mechanism as of 2017, but the government is assessing whether to expedite the implementation.

3.2.5.1 Eligibility

Although still in development, the Irish and Italian central buyer schemes are both intended to be open to all potential capacity providers including both new and existing resources, and demand response. Central buyer models allow different contract durations, ranging from one to fifteen year contracts in the EU mechanisms (incl. GB).

In terms of geographic scope, the Irish mechanism is expected to operate across the whole island of Ireland. The Italian mechanism, by contrast, is being designed as a zonal system which will establish different prices for capacity per zone. The British mechanism is open to the participation of interconnectors, but not to foreign capacity. The Irish and Italian schemes have not yet developed rules for foreign capacity participation but intend to enable foreign participation.

3.2.5.2 Allocation process

The central buyer mechanisms, by definition, involve a central process in which all capacity providers offer their capacity and it is 'bought' by a single buyer on behalf of electricity suppliers/consumers.

[63] See Commission decision C (2014) 5083 final of 23.7.2014 in Case SA.35980 (2014/N-2) – United Kingdom - Electricity market reform – Capacity market. The public version of the decision is available at: http://ec.europa.eu/competition/state_aid/cases/253240/253240_1579271_165_2.pdf.

[64] Although the sector inquiry has not gathered additional information on mechanisms in countries outside the 11 included Member States, key points from the design and operation of these mechanisms still offer valuable insights for the inquiry and are therefore occasionally mentioned in this report.

3.2.5.3 Capacity product

In the Irish and Italian schemes, the capacity product is a 'reliability option' which will oblige the capacity providers to pay the difference between a reference electricity price and a strike price specified in the reliability option contract whenever the reference price exceeds the strike price. In the British mechanism, providers must have delivered their contracted capacity in any periods in which it was required, and if they failed to deliver (or only partially delivered) after a four hour warning was given, penalties will apply.

3.2.6 De-central obligation

The only de-central obligation scheme subject to the inquiry is the one being implemented in France.[65]

3.2.6.1 Eligibility

All potential capacity providers including demand response and both new and existing projects can be granted capacity certificates in the French scheme.

The French mechanism is not currently open to interconnectors or foreign capacity but France has publically consulted on the potential for direct interconnector or foreign participation in future.

3.2.6.2 Allocation Process

In the de-central obligation model there is no central buyer but capacity certificates are tradeable, so once suppliers have an obligation to hold capacity certificates a market is created. The certificates can be bilaterally traded, or potentially traded on exchanges.[66]

3.2.6.3 Capacity product

In the French scheme, capacity providers must make the capacity they have sold as certificates available in peak demand hours identified in advance by the TSO. In these hours, suppliers must also ensure that they have sufficient certificates to cover the consumption of their consumers in a cold winter. If suppliers hold insufficient certificates, or capacity providers make insufficient capacity available, capacity imbalance penalties will apply.

3.2.7 Market wide capacity payments

Ireland introduced a market wide capacity payment mechanism in 2007 to provide additional revenue to remunerate market participants for their fixed costs.[67]

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[65] The Commission opened a formal investigation into the measure on 13 November 2015. See: http://europa.eu/rapid/press-release_IP-15-6077_en.htm. The Commission's decision is publicly available (in French) at: http://ec.europa.eu/competition/state_aid/cases/261326/261326_1711140_20_2.pdf

[66] Note in central buyer schemes the secondary trading of capacity obligations / contracts may also be possible after the initial allocation through the capacity auction/s.

3.2.7.1 Eligibility

The capacity payments are paid to all generators in the market, as well as to providers of demand-response and storage that contribute to meeting demand.

The Irish scheme also makes payments to foreign capacity providers – however, it does this by providing a capacity payment on top of the Irish electricity price for providers of imports to Ireland (and also deducts the capacity payment for exporters of electricity from Ireland).

3.2.7.2 Allocation process

As with the targeted capacity payment schemes, the Irish market wide capacity payment involves an administrative price-setting process where the value of capacity payments is calculated by the Irish and Northern Irish regulators. Capacity providers receive a capacity payment for every 'trading period' in which they were available.

3.2.7.3 Capacity product

Capacity payments in the Irish market are highest at times of tighter capacity margins, which incentivises generators to be available at these times. Moreover, the generators have to declare themselves available to be called-upon by the TSO in real-time and performance penalties apply if they do not comply instructions from the TSO.

3.3 Conclusions

29 mechanisms have been identified in the eleven Member States under assessment – including past, existing and planned mechanisms. Three Member States have used tenders for new capacity, and six examples of strategic reserves were found. Four countries have used targeted capacity payment schemes, but the inquiry found nine examples of this model because Spain and Portugal operate more than one different scheme of the same type. Two Member States are developing central buyer mechanisms similar to those already operating in the United States and UK. Only one Member State is developing a de-central obligation mechanism, and there is only one example of a market wide capacity payment mechanism.

There seems to be a trend away from price-based and towards volume-based schemes. There is only one proposed capacity payment scheme; all schemes currently proposed or in development are volume-based.

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[67] Ireland's electricity market operates as a single market across the Republic of Ireland and Northern Ireland. Due to the cross-jurisdictional market arrangements in the Irish electricity system, where the Commission refers to Ireland in this report it is usually referring to the island of Ireland which comprises territory of the Republic of Ireland and the United Kingdom. Although the Irish electricity market is currently being reformed, in the current design generators can only bid their short run marginal costs in the energy market which means prevents peaking generators recovering their fixed costs without additional remuneration.

The following Chapters will describe and assess specific features of the identified schemes in more detail in order to learn lessons from the design and operation of the various capacity mechanisms identified.

4. ADEQUACY ASSESSMENTS AND RELIABILITY STANDARDS

4.1 Introduction

A necessary starting point in the process of determining whether or not to implement a capacity mechanism is to make an assessment of the generation adequacy[68] situation and how it is expected to develop in the future. Based on the outcomes of such adequacy assessment Member States can establish whether and how much intervention is necessary, for instance by comparing the outcome of the adequacy assessment to a pre-determined 'reliability standard' that sets a level of security of supply that is deemed appropriate.

In the context of the sector inquiry the Commission has asked public bodies and market participants whether and how they have carried out adequacy assessments and how the assessments relate to reliability standards – where these are in place – and how they have influenced the choice and the design of the existing or future capacity mechanisms. Respondents were also asked for information on past reliability problems and their expectations for the future.

As adequacy assessments and reliability standards are used to define the potential generation adequacy problem, they are also a necessary basis for the analysis in the subsequent chapters, namely, whether market or regulatory failures have been correctly identified, whether alternative and/or complementary measures have been considered and put in place, and whether the remedies that have been introduced have been appropriate to address the identified problem.

4.2 Findings of the sector inquiry

4.2.1 Reliability incidents are rare

The sector inquiry asked public bodies whether reliability issues had occurred in the past in their Member State or are expected to occur in the future. The respondents indicate that reliability issues due to generation inadequacy have been extremely rare in the past five years.

In nine out of ten Member States, no such problems have occurred at all. The only exception was Italy, where such issues had arisen on the islands of Sardinia and Sicily which are not well connected to the grid on the mainland. This confirms observations made in the Commission's 2014 Energy Prices and Costs report which concluded that Europe outperforms all other regions in the world when it comes to reliability of supplies.[69] It also confirms one of the conclusions in Chapter 2 that the general increase in capacity and in particular in RES, has resulted in a situation in which the difference between peak demand and supply has widened

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[68] Throughout the Report the term 'generation adequacy' refers to the ability of the totality of generating units to meet the demand at all times. It is distinct from the wider 'system adequacy' which relates to the ability of the entire system, i.e. including notably the transmission and the distribution grid, to meet demand at all times.

[69] Commission Staff Working Document, SWD(2014)20 of 22 January 2014: http://eur-lex.europa.eu/resource.html?uri=cellar:ba385885-8433-11e3-9b7d-01aa75ed71a1.0001.01/DOC_3&format=PDF

and capacity margins – that is, the simple difference between installed capacity and peak demand – have increased.

Table 4: The necessity of capacity mechanisms and actual reliability problems

The necessity of capacity mechanisms and actual reliability problems							
Country	Do Market Participants believe the mechanism is necessary?	Have reliability problems occurred in the last 5 years?	Are reliability problems expected in the future?	Country	Do Market Participants believe the mechanism is necessary?	Have reliability problems occurred in the last 5 years?	Are reliability problems expected in the future?
Belgium	Y	N	Y	Italy	Y	Y, in Sardinia and Sicily	Y
Denmark	Divided	N	Y	Poland	Y, but doubts as to appropriateness of the chosen mechanism	N	N
France	Y	N	Y	Portugal	Y	N	N
Germany	Y	N	N	Spain	Y	N	Y
Ireland	Y	N	Y	Sweden	Divided	N	Y

Source: European Commission based on replies to sector inquiry[70]

4.2.2 More adequacy problems are expected in the future

Although the Member States do not experience reliability issues at present, Table 4 also demonstrates that a clear majority of public bodies indicate that they are of the opinion that reliability problems are expected to arise in the coming five years. Only in three out of ten Member States the expectation is that no reliability problems will occur in the medium term, but these Member States – expect their overcapacity to reduce in the longer term even though they currently display a comfortable capacity margin.

As discussed in Chapter 2, a number of market developments and failures have contributed to the increased uncertainty about future generation adequacy. Public bodies have expressed two key concerns, firstly, the expected closure of existing plants – mentioned by public bodies from Belgium, France, Poland and Spain – and, secondly, the inability of the future generation mix to cover peak demand, as underlined by public bodies from Belgium, France, Ireland, Italy, Poland, Portugal, Spain and Sweden. Closely connected to this concern is the impact of intermittent renewables.

In a majority of cases, these concerns originate from the 'missing money' problem referred to in Chapter 2: as the shares of intermittent renewables increase and the profitability of conventional power plants declines the question arises whether sufficient flexible back-up capacity will be available when demand peaks but renewables cannot produce.

The underlying reasons stated by Member States for the occurrence of missing money in their local markets appear to be different. In Germany for instance, the rapid increase of renewables combined with the phasing out of nuclear power plants and difficulties in expanding the grid have led to local adequacy issues, which may be alleviated in the long run

[70]Croatia did not provide information on these questions.

when additional transmission lines are built. As a result, Germany has introduced a measure that prevents power plants in the South from closing, the network reserve.

In Poland, the concerns are not of a locational, but rather of a temporal nature: increased emission standards will force a number of old and polluting coal power plants out of the market, but already committed, new generation units may not be operational before the old ones will have closed. Poland therefore anticipates its contingency reserve to be transitory.

Ireland and Italy set-up their tender and capacity payment mechanisms respectively in direct response to acute adequacy concerns that occurred in 2003. Similarly, in Belgium the lower profitability of (ageing) thermal plants was expected to lead to the closure of power plants and caused the Member State to implement its strategic reserve in 2014.

Identifying the underlying causes properly can help targeting the need, type and size of a capacity mechanism, but even where a solution responds to the identified problem, it is important that it is proportionate, that alternative solutions have been assessed properly and that it is not distortive for instance by harming market functioning or increasing market power.

4.2.3 Member States carry out increasingly advanced adequacy assessments

To substantiate their concerns about the future generation adequacy, respondents to the sector inquiry often refer to the assessments carried out for their Member State, usually by their TSO.

The generation adequacy assessment needs to take into account that both demand and supply vary considerably during the day, during the year and over the years. They are dependent on a wide array of variables. Moreover, in liberalised markets without central planning, the decision on whether to invest in or divest generation units and whether to produce or not is in the hands of market participants and – for reasons of business confidentiality – there is often very limited information available about the commercial plans of individual operators. An additional challenge is that adequacy assessments, in order to provide useful information in time to devise and implement appropriate remedies, need to be able to look far ahead, e.g. five to ten years, which significantly increases uncertainty.

All Member States that are part of the sector inquiry measure the security of supply situation in their country by carrying out an adequacy assessment in which one or more methodologies are applied that give an indication of the potential of the generation fleet to meet demand in the system at all times and under varying scenarios. Moreover, in all Member States the TSO is the main responsible body for carrying out the calculations. In a minority of countries this is followed by either the government or the national regulatory authority ('NRA') scrutinising the TSO's data and publishing a monitoring report.

Table 5: Member State practice in carrying out adequacy assessments

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

Source: European Commission based on replies to sector inquiry[71]*, see Box 1 for a description of capacity margins, LOLP, LOLE, and EENS*

With an increasing proportion of variable renewable resources, electricity systems have become more complex. To address this increased complexity, a majority of Member States have replaced relatively simple, 'deterministic' assessment metrics – which simply compare the sum of all nameplate generation capacities with the peak demand in a single one-off moment – by more complex 'probabilistic' models, which are able to take into account a wide range of variables and their behaviour under multiple scenarios. This includes not only state of the art weather forecasts, but also factors in less predictable capacity sources such as the contribution from demand response, interconnectors or renewable energy sources.

Such advanced adequacy assessments provide signals to market participants, TSOs, regulators, consumers and policy makers on the most probable development of the adequacy situation. On this basis, parties active in the electricity sector can choose to invest or divest and to produce or consume more or less electricity. Box 1 briefly sets out the various methods and their advantages and disadvantages.

Box 1 Methodologies to assess generation adequacy: from deterministic to probabilistic models

Today, a variety of adequacy assessment methodologies are applied across Europe. One of the simplest measures to determine the level of generation adequacy is the ***capacity margin****. This 'deterministic' methodology simply expresses the relation between peak demand in the electricity system and the reliably available supply, usually as a percentage. For instance, a system with 11GW of installed capacity and 10GW of peak demand has a 10% capacity margin. In two of the eleven Member States only this relatively simple capacity margin is calculated.*

[71] Croatia did not provide information on these questions.

However, deducing the likelihood of generation related adequacy problems from these simple metrics is not possible with a high level of accuracy/confidence for the following reasons. A simple capacity margin calculation does not give a reliable impression of the adequacy situation due to the increase in variable renewables, as shown in Chapter 2. No form of generation can always output its full nameplate capacity with 100% reliability. The intermittent nature of solar and wind generation means that these sources in particular cannot always be assumed to be available and contribute at nameplate capacity during periods of high demand. The practice of assigning an expected average contribution to various sources of input is referred to with the term ***de-rating.***

Measuring capacity margins by comparing peak demand and de-rated total supply can therefore improve the accuracy of the capacity margin a measure of generation adequacy. However, although a deterministic model can determine an average contribution that can be safely expected to be received from the various sources, it cannot do this as accurately as a probabilistic model. Furthermore, a simple deterministic method can conceal internal grid bottlenecks. For instance, in Germany the overall amount of generation is expected to remain positive compared to its overall demand for at least the coming five years, but nevertheless a network reserve has been in place and regularly used in the South of Germany since 2012 to cope with network constraints within Germany by enabling re-dispatch capabilities for the TSOs in the southern regions.

*A more sophisticated method to measure generation adequacy is the calculation of a loss of load probability (**LOLP**), which quantifies the probability of a given level of unmet demand over a certain period of time. Figure 28 above shows that around half of the Member States carry out a LOLP calculation. Often, LOLP is expressed as a loss of load expectation (**LOLE**) which sets out the expected number of hours or days in a year during which some customer disconnection is expected. (for example, if 1 day in 10 years some customers would need to be disconnected, LOLE would be 0.1 days or 2.4 hours). This probabilistic approach can take into account variations in demand over the years as a result of climate fluctuations.*

*LOLP/LOLE do not measure the total shortfall in capacity that occurs at the time when there are disconnections, and neither LOLP/LOLE nor capacity margins measure the amount of unmet demand. This would require a measurement of expected energy not served (**EENS**) which would be expressed in MWh over a specific time period (eg. a year). EENS thus also makes it possible to monetize the shortfall in a system where VOLL[72] has also been calculated (see below) since the amount of EENS can then be multiplied by VOLL.*

4.2.4 Member State practice in setting reliability standards

Adequacy assessments contribute to an informed decision about the necessity of capacity mechanism in the market. If a capacity mechanism is introduced, a transparent reliability

[72] For a more detailed explanation of VOLL, see paragraph 2.2.2.1

standard is needed to determine the appropriate size of the mechanism. A reliability standard expresses a trade-off between cost and reliability and determines which level of security of supply is deemed appropriate. Although it is easy to argue that a system must be 100% reliable, achieving 100% reliability is likely to entail extremely high costs and technically impossible.

As Table 6 demonstrates, a majority of the Member States included in the sector inquiry make use of a reliability standard to identify the appropriate level of security of electricity supply in their territory.

In Member States that calculate a LOLE-expectation in the context of their adequacy assessment, the standard is often expressed as a tolerated level of LOLE-hours. Targets generally range from 3 to 8 hours. In Member States that only calculate a capacity margin, the reliability standard or target is expressed in terms of a capacity margin percentage. Comparing the outcome of the adequacy assessment with the standard provides an indication as to potentially missing capacity and hence the need for and size of capacity mechanism.

Table 6: Member State practice in setting a reliability standard

Legal Reliability Standard or Target?							
Country	Y/N	Which?	Link with VOLL?	Country	Y/N	Which?	Link with VOLL?
Belgium	Y	LOLE (average) < 3h LOLE (extreme 95%) < 20h	N	Italy	N	In the future: LOLP	Possible future regime: curve linked to VOLL of 3000,-
Denmark	N	Non-legislative target for TSO to ensure max. 5 min. of disconnections per consumer/year (LOLE < 0.25).	N	Poland	Y	Reserve capacity levels	N
France	Y	3 hrs LOLE	Yes, 20.000,-	Portugal	Y	Reserve Margin and LOLE 8hrs	N
Germany	N	n.a.	N	Spain	Y	Capacity margin of 10%	N
Ireland	Y	LOLE < 8h	Y, 10.898,-	Sweden	N	Reserves to meet N-1 is target for TSO	N

Source: European Commission based on replies to sector inquiry[73][74][75]

[73] The Belgian LOLE (P95) refers to a 95th percentile standard according to which during severe conditions of which the chance is 5% (i.e. a very cold winter that occurs once in 20 years) the LOLE must be inferior to 20 hours.

[74]Croatia did not provide information on these questions.

[75] The German capacity reserve is triggered when the day-ahead or intraday market do not clear and all other instruments have been exhausted. The market not clearing means in practice that offers at the maximum bid price (3,000 and 10,000) remain unmatched in the day-ahead and intraday market respectively. Balancing responsible parties pay 20.000 Euro/MWh

To determine their reliability standard, a number of Member States make use of a calculation of VOLL. Where a Member State calculates and applies VOLL, it estimates the value an average consumer places on secure electricity supplies at any point in time. In other words, it is the price point at which the consumer is indifferent between paying for electricity and being cut off. The higher the degree of protection desired, the more (back-up) capacity is needed and therefore the higher the price tag attached to it. In order to determine the cost of additional protection against disconnections through additional capacity investment, some countries calculate the cost of new investment by estimating the cost of a 'Best New Entrant (BNE)' or 'Cost of New Entry (CONE)'. The estimate is usually based on the costs of a new peaking plant (since this represents a cheaper way of providing marginal capacity than a baseload plant). A comparison of VOLL and BNE/CONE can identify the point at which the value for consumers of investment in additional capacity is maximised – at the point at which the incremental cost of insuring customers against power cuts is equal to the incremental cost to customers of power cuts.[76] Linking the reliability standard to the level of capacity that reflects the maximum value consumers place on being supplied with electricity, means that an economic efficient level of protection is set and that expensive overprotection is avoided.

Less than half of the countries calculate VOLL and use it as their basis for determining their reliability standard. A possible reason that not all Member States make use of a VOLL to ensure an economically sensible level of protection may be that it is difficult to calculate an appropriate average VOLL. Electricity has a different value for different users and differs over time. An additional complexity, as underlined in Chapter 2, is that electricity consumers are not able to individually express their valuation of electricity for every time slot. VOLL calculations therefore attempt to replace the true (but unknown) value of disconnection with an administrative average value. The average VOLL in each Member State or bidding zone may also be different, reflecting the different cost of a MWh of unserved energy to different types of consumers and/or consumers in different parts of Europe.

Moreover, a majority of the countries that have established a reliability standard do not link the capacity demanded through their capacity mechanism to the achievement of this standard. This means that the reliability standard does not fulfil its main function, namely to ensure an appropriate level of capacity. For instance, respondents to the sector inquiry argued that the amount of capacity to be procured in the Belgian strategic reserve and in the interruptibility scheme in Spain was overestimated.

The sector inquiry also provides evidence that some Member States fail to scale down their capacity requirements on the basis of a comparison between the standard and the outcome of

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after deployment of the reserve, if they contributed to the shortage in the system and therefore the need to deploy the capacity reserve.

[76] One of the countries in the sector inquiry considering such approach is Ireland. It has provided a more thorough discussion on this topic in its consultation paper on the detailed design of its envisaged capacity mechanism: http://www.semcommittee.eu/GetAttachment.aspx?id=375f5e77-1adb-4f30-baac-3f5470efa85d

the adequacy assessment. For instance, Spain applies a 10% capacity margin as its reliability standard. The current situation demonstrates there is 43% capacity margin. Instead of limiting the capacity measure to the achievement of the applicable standard, Spain has continued to pay capacity payments.

4.3 Assessment

4.3.1 The absence of a common approach in assessing adequacy

The increased concerns of Member States about future generation adequacy have led to the development and application of more sophisticated and more reliable adequacy assessments. However, the fact that an increasing number of countries apply a similar advanced methodology, based on an hourly LOLE, does not mean the outcomes can now be compared easily with one another. In fact, the assumptions used by Member States to set LOLE vary widely and are not clearly communicated. This has a number of potential negative effects: it decreases transparency on the actual level of protection, it reduces the potential for cross-border solutions and it may lead to inappropriately sized capacity mechanisms. Since assumptions and scenarios chosen in the individual assessment (e.g. "one in 20 year" vs "one in 50 year" winter peak, or how imports are taken into account in a national adequacy assessment) can have an important impact on the outcome of the assessment, it is important to make the assessment as transparent and comparable as possible.

The absence of a common approach means that no comparison between the Member States can be made as to their relative generation adequacy without fully exploring the individual methodologies used. As a result, Member States cannot simply rely on the assessment of a neighbouring country and use that as input to their own assessment. As such, the potentially important contribution of interconnectors may not be fully used. The diverging approaches of Member States become apparent in defining what constitutes a LOLE-event and in the approach to de-rating the various elements in the generation mix.

There is no common definition of what qualifies as a 'reliability event' and thus contributes to LOLE-hours. As a result, it is not clear to what extent interventions by the TSO to prevent brownouts[77] or blackouts – such as issuing generation maximisation instructions, using ancillary services to fill a supply gap, or implementing voltage reductions – qualify as LOLE-events. Where this question has not been answered with sufficient clarity, the ensuing uncertainty not only makes comparability of the level of generation adequacy across borders problematic, it also creates a large discretion for TSOs to determine the volume of the additional safety margins they believe are needed.

[77] A brownout is less serious than a blackout in the sense that it is merely a short voltage reduction and not a complete loss of power. Brownouts can be intentionally used by network operators to temporarily accommodate increased demand. Brownouts can however damage special equipment used in industrial processes that require stable power flows.

There is a risk related to leaving large margins of discretion to the TSO, because depending on its responsibilities and regulation, it may have an incentive to overprotect. A transparent approach is therefore important to objectivise risk perception. There is great consensus among both public bodies and market participants responding to the sector inquiry questionnaires that a more harmonised approach to determining generation adequacy is necessary.

Box 2: Putting LOLE in perspective

LOLE values are generally deduced from a much longer term average. The 3 hours on average per year LOLE standard in France for instance is derived from a calculation that predicts a 30 hour disruption every ten years. To put the LOLE standards into perspective, even the most relaxed standard currently applied in Europe, of 8 LOLE-hours per year, translates into a system security level of 99.90% - i.e. 99.9% of the time no one will be involuntarily disconnected.

Moreover, it is important to realise that LOLE hours should not be viewed as hours in which a major blackout takes place leaving entire market areas without power, but may be solved by TSOs without major impacts, i.e. by using instruments such as temporary voltage reductions or the selective disconnection of large industrial users. When not seen in perspective, a Loss of Load Expectation may give the wrong impression that blackouts are expected.

Indeed, for most Member States network failures, for example after weather events that damage network infrastructure, have historically led to far more involuntary unmet demand than generation inadequacy[78].

The absence of a common approach also becomes apparent with regard to the de-rating[79] of capacity (most importantly for renewables and imports), which further complicates cross-border comparison and objective insight into the actual adequacy situation in a country or bidding zone. There may be good reasons that contributions of such sources differ per country, but a common approach on the underlying principles would create an objective basis for cross-border comparison.

4.3.2 Reliability standards are not used to ensure appropriate intervention

Ideally, comparing the outcomes of an adequacy assessment with the desired level of protection laid down in a reliability standard that takes into account the average consumer's willingness to pay for security of supply provides an objective indication as to whether or not intervention in the market to foster generation adequacy is necessary and to what extent. At present, this is however not common practice.

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[78] In 2014 ENTSO-E identified over 1000 security of supply incidents. Most of these were minor but there were some more serious disturbances, for example storms on 12 February 2014 leaving 250,000 homes in Ireland without power. See https://www.entsoe.eu/Documents/SOC%20documents/Incident_Classification_Scale/151221_ENTSO-E_ICS_Annual_Report_2014.pdf

[79] See Box 1 for a description of de-rating.

Some Member States do not have reliability standards and Member States that do apply them often do not explicitly link them to the type and extent of their capacity mechanism. Moreover, a majority of countries does not calculate a VOLL for their market, nor use it in setting a market price cap or a reliability standard.

This results in a situation in which the necessity and the size of a capacity mechanism are not always based on a proper economic assessment. As a consequence, there is a risk that interventions in the market become subjective and hence sub-optimal. Objectivising the need for and degree of interventions can be done by adopting a well-defined VOLL as a key indicator in determining an appropriately maximum level of protection.

4.4 Conclusions

Despite the absence of reliability issues, Member States are concerned about future generation adequacy for a variety of reasons, mostly linked in some way to the missing money problem. A thorough problem identification can help tailoring an intervention in the electricity market to solve the precise problem and adequacy assessments can help quantifying the extent of the adequacy problems. By using different scenarios in a transparent and comparable manner, adequacy assessments can help demonstrate whether an identified problem is of a transitional nature. A reliability standard can ensure that intervention takes place up to a level consumers would wish to pay for.

However, practice demonstrates that whilst increased concerns about generation adequacy have been accompanied by the development of better adequacy assessments, the proper follow-up to those assessments does not take place, mostly because reliability standards are not always based on sound economic assessment. As a result, regulatory decisions on capacity markets are not sufficiently evidence-based and most capacity mechanisms are not tailor-made to secure the capacity shortfall identified by an adequacy assessment compared against a reliability standard based on VOLL.

Demonstrating necessity of intervention is a prerequisite for any capacity mechanism to be accepted under State aid rules. A more harmonised and transparent approach to adequacy assessments and VOLL can contribute to objectivising the need for and size of interventions.

Several harmonisation efforts are already ongoing at European level. The TSOs of the Pentalateral Energy Forum[80] have carried out a common adequacy assessment at regional level using a probabilistic approach with an hourly resolution. It includes a common approach to de-rating RES based on historic climate data, and to the de-rating of interconnection capacity.

Also ENTSO-E publishes a Europe-wide yearly system outlook and long term adequacy forecast (SO&AF) on the basis of Article 8 of the Electricity Regulation (EC) No 714/2009.

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[80] Austria, Belgium, France, Germany, Luxembourg, the Netherlands, Switzerland. The report: http://www.tennet.eu/nl/fileadmin/downloads/News/2015-03-05_PLEF_GAA_Report_for_SG2_Final.pdf

ENTSO-E develops and improves its methodology regularly and has established a Target Methodology that will include the use of a probabilistic method, an extensive range of indicators and state of the art RES and climate simulations. The first SO&AF under the updated methodology will be published in 2016.

As regional and European-wide methodologies mature and become more reliable, they should increasingly be used as a basis for assessing the necessity of introducing capacity mechanisms. In its energy market design initiative, the Commission intends to provide a European framework for transparent and harmonised generation adequacy assessments and standards. In the meantime however, Member States should ensure they undertake thorough national adequacy assessments following emerging best practice, and compare the situation without intervention against an economic reliability standard, before intervening in their markets.

5. DESIGN FEATURES OF CAPACITY MECHANISMS

5.1 Introduction

This chapter presents the findings on the design features of the capacity mechanisms in the 11 Member States covered by the sector inquiry.

Once Member States have assessed their generation adequacy situation and concluded that there is a need for the introduction of a form of support for generation capacity, they face a range of choices to design a suitable capacity mechanism to address the identified adequacy problem. There are a number of considerations to be made irrespective of the type of capacity mechanism. Chapter 5 aims to present the most important of those design choices, which are considered in three categories:

- **Eligibility**: who gets to participate in the capacity mechanism?
- **Allocation**: how does the selection process among the eligible parties work and how is the level of capacity remuneration determined?
- **Product design**: what do participants in the scheme have to do, and what happens if they don't do it?

For each of those categories, examples from the capacity mechanisms found in the inquiry will be presented to illustrate the impact of those choices on the effectiveness of the mechanism.

5.2 Eligibility

5.2.1 Eligibility criteria in capacity mechanisms

Once Member States have identified the residual market failures that they want to address with a capacity mechanism, they need to decide which capacity providers can contribute to procuring the identified capacity need and should be made eligible to participate in the mechanism. Well-designed eligibility criteria enable an optimal selection of capacity providers to address the identified security of supply problem. Open criteria encourage participation of all potential sources, whereas more narrowly defined criteria limit the pool of potential contributors.

This section analyses the eligibility options available to policy makers, and assesses whether there may be valid reasons for limiting a capacity mechanism to a single or very few capacity sources. The eligibility rules can explicitly or *de iure* limit participation to certain pre-determined capacity types, or set performance related criteria that have the equivalent effect by *de-facto* excluding of one or more types.

5.2.2 Findings of the sector inquiry on eligibility

The sector inquiry demonstrates that Member States design and target the eligibility criteria in their capacity mechanism mainly on the basis of:

(1) *Generation technologies*: Member States may for different reasons selectively exclude specific generation technologies from a capacity mechanism or favour others within the mechanism. Indeed, the majority of capacity mechanisms covered by the present inquiry is *de facto* targeted at one or more technologies and excludes others;

(2) *Demand response*: there are several reasons Member States may want to foster the participation of demand response. As underlined in Chapter 2, an active demand side could deliver significant benefits to market functioning. And because some forms of demand response can deliver capacity at short notice it is increasingly a useful competitor in capacity mechanisms.

(3) *Storage providers*: Member States furthermore need to determine whether storage can usefully contribute to address the generation adequacy they have identified. Storage can significantly contribute to security of supply by storing electricity when it is cheap and abundant, and again releasing it, usually on short notice, when it is scarce and expensive. Storage can however only provide that capacity (or in other words be available) for short periods of time.

(4) *New vs. existing capacity*: another eligibility choice that Member States need to make is whether they want to include new or existing capacity in their mechanism, or a combination of both. Where Member States were concerned that no investments in new capacity took place, they have often tended to focus on attracting new capacity, while when they were concerned that a considerable amount of existing capacity would go offline in the near future, they have often tended to focus on keeping existing plants on stand-by outside of the market (i.e. they have introduced strategic reserves).

(5) *Location*: in case of a geographically delimited capacity problem, Member States have sometimes chosen to limit participation to the capacity mechanism to the capacity providers in the zone that experiences the capacity problem. Additionally, many Member States only consider capacities on their own territory and do not take into consideration foreign capacities.

This section is divided into sub-sections that address each of these design considerations.

Table 7 below provides a general overview of the types of capacity providers that are sought by each of the capacity mechanisms covered by the sector inquiry:

Table 7: Overview of eligible capacities

Member State	Capacity mechanism	Eligibility
		Tender for new capacity
Belgium	Tender for new capacity	CCGT and OCGT
France	Tender for new capacity in Brittany	CCGT
Ireland	Tender for new capacity	Thermal generation capacity
		Targeted capacity payment
Italy	Targeted capacity payments	Generation capacity that can participate in the ancillary services market
Poland	Operational reserve	Centrally dispatched generation capacity
Portugal	Availability incentive	Thermal generation capacity
	Investment incentive	Hydro
Spain	Availability service	Thermal generation (except nuclear) and hydro (with storage)
	Investment incentive	Nuclear, gas, coal, hydro and oil entering into service before 1 January 2016
	Environmental incentive	Coal plants
	Support to power plants using indigeneous coal	Coal plants
		Reserve
Belgium	Strategic reserve	Generation capacity announced for closure or mothballed and non-generation DSR Minimum demand response purchase obligation of 50MW
Denmark	Strategic reserve	All types of generation capacity (existing and new), DSR and storage
Germany	Network reserve	All types of generation capacity (incl. storage) announced for closure or mothballing but considered "system relevant". If insufficient, tender for additional capacity consisting *de facto* of foreign plants (incl. storage)
	Capacity reserve	All types of generation capacity (existing and -in future- new)
Poland	Cold contingency reserve	Centrally dispatched generation capacity entitled to a temporary derogation from IED emission standards as of 1 January 2016
Sweden	Strategic reserve	Generation capacity and demand response. Minimum demand response purchase obligation of 25%
		Central buyer
Italy	Central buyer reliability obligation scheme	All generation capacity (existing and new). Italy exploring to include DSR and foreign capacity as of 2017 auction
Ireland	Central buyer reliability obligation scheme	All types of generation capacity (existing and new), DSR and storage. In principle also open to cross border generation capacity.
		De-central obligation
France	Supplier obligation	All types of generation capacity (existing and new), DSR and storage. France is publicly consulting on possibility of direct cross border participation.
		Market-wide capacity payment
Ireland	Market-wide capacity payments	All types of generation capacity (existing and new), DSR and storage, foreign capacity and interconnectors
		Interruptibility scheme*
Germany	Interruptibility scheme	Demand response >50MW
Italy	Interruptibility scheme for Sardinia and Sicily	Demand response >1MW
	Interruptibility scheme for the mainland	Demand response >1MW
Ireland	Interruptibility scheme	Demand response >0.1MW and not active as demand response in the market
Poland	Interruptibility scheme	Demand response >10MW
Portugal	Interruptibility scheme	Demand response >4MW
Spain	Interruptibility scheme	Demand response >5MW or >90MW (two auctions)

*size requirements only given for interruptibility schemes - size requirements also apply in other schemes

Source: European Commission based on replies to sector inquiry

5.2.2.1 Generation technology neutrality

Rationale for selectivity

A clear majority of the existing and planned capacity mechanisms covered by this inquiry exclude one or more generation technologies. There appear to be various reasons why governments wish to encourage or discourage the participation of certain technologies. Environmental considerations for instance may inspire the exclusion of lignite, coal or nuclear power plants. Member States also use a capacity mechanism to promote indigenous energy sources as a secondary objective. This is for instance the case of the investment incentive mechanism in Portugal, in which only hydro power plants can participate. It was also the case in the –now expired– Spanish scheme in support of power plants using indigenous coal.

Member States may also wish to narrow participation in their capacity mechanism to target the type of capacity that they consider most suitable to alleviate a capacity shortage. Where existing capacity for example cannot ramp up and down quickly enough to react to sudden changes in demand, a Member State may wish to target a mechanism only to flexible capacity such as demand-response, storage or gas-fired generation.

Some capacity mechanisms explicitly exclude capacities which already receive subsidies via other, separate support schemes. This may on the one hand be mandated by rules prohibiting the cumulation of aid. On the other hand, full participation and fair competition can only work if a level playing field exists between potential capacity providers more generally, through the elimination of subsidies other than capacity payments to specific capacities.

The sector inquiry found that most Member States support renewable energy and combined heat-power generation in principle through separate support schemes. While there are in principle different objectives behind RES support schemes (which aim to reduce greenhouse gas emissions) and capacity mechanisms (which aim to ensure security of supply), there is some recognition of the value of RES for security of supply. Accordingly, more recent capacity mechanisms tend to allow RES to participate (while at the same time including safeguards to avoid cumulation of aid from different mechanisms). This is for instance the case of the French de-central obligation scheme where RES producers are awarded certificates (and receive the higher of the income from the certificates or the "normal" RES subsidies), and the British capacity market (where RES can participate provided they opt out of alternative support schemes). It appears that RES will also be able to participate in the planned Italian and Irish reliability option mechanisms.

Openness of capacity mechanisms to different generation technologies

To assess how the different types of capacity providers participate in capacity mechanisms the following sections distinguish between the explicit and implicit exclusion of generation technologies.

Explicit exclusion

Some capacity mechanisms are explicitly technology specific, determining a single type of generation technology to fulfil the identified capacity need. This applies to all tenders for new capacity: the tenders in Brittany (CCGT) and Belgium (CCGT and OCGT) targeted only gas-fired power plants, in Ireland it was limited to thermal generation capacity.

The only capacity payment schemes explicitly open to all generation technologies are the Irish and Italian one.[81] All the other capacity payment mechanisms covered by the inquiry are open to specific generation technologies. Typically, participation is limited to thermal generation,

[81] Participation in the Italian scheme is, in principle, open to all plants admitted to participate in the ancillary services market. However, size and performance requirements for the ancillary services market lead to the implicit exclusion of certain generation technologies, such as renewables.

with the exception of the Portuguese investment incentive mechanism which is open only to hydroelectric plants. In some cases, only a subset of thermal plants is eligible, such as for instance in the Spanish environmental incentive scheme and the Spanish scheme for power plants using indigenous sources which are only open to coal-fired power plants.

In contrast, none of the strategic reserves explicitly excluded certain technology types. As discussed in the next section, there were however implicit criteria that *de facto* limited participation.

The market-wide capacity mechanisms in the inquiry were usually open to all generation technologies. As already explained above, they however differ in their treatment of RES.

<u>Implicit exclusion</u>

Eligibility criteria are in some instances defined in such a way that in practice only certain capacity providers can participate.

A first category of requirements that may lead to the exclusion of certain types of generation are **size requirements**. In the mechanisms covered by the inquiry, they range from a 0.1MW threshold –for certification in the French de-central obligation scheme– to a 450MW threshold for participation in the tender for new capacity in Brittany.[82] The higher the threshold, the more likely it *de facto* excludes smaller generators (especially RES) and also demand response providers.

A second category relates to **environmental standards**. The sector inquiry found the example of the Spanish environmental incentive mechanism that required coal plants to install a sulphur dioxide filter to participate. In contrast, participation in the Polish cold contingency reserve is reserved for plants that enjoy a temporary derogation from emission standards under the industrial emissions Directive[83] and are therefore too polluting to operate in the market. The mechanism therefore in practice addresses old coal and lignite plants only.

A third category includes criteria that are based on the **technical performance** of the capacity provider, such as power plant efficiency, ramp-up time or the ability to provide certain ancillary services. Power plant efficiency requirements were for instance set in the Belgian and French (Brittany) tenders for new capacity.[84] In both cases, the Member State also required that the power plants were able to provide certain ancillary services. As these tenders were explicitly addressed at specific types of newly built power plants, the efficiency and ancillary services requirements did in practice not exclude certain technologies but rather act

[82] Size requirements are for example to be found also in the Belgian tender for new capacity (400 MW for CCGTs and 40 MW for OCGTs), the tender for new capacity in Ireland (50 MW), the Italian targeted capacity payments (10 MW), the Portuguese targeted capacity payment mechanisms (30 MW), the Spanish investment incentive capacity payment mechanism (50MW) and all interruptibility schemes.
[83] Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions.
[84] In the Belgian example the efficiency requirements were different for OCGTs and CCGTs.

as minimum standards for the offers.[85] Participation in the Italian targeted capacity payment mechanism is only open to plants that are admitted to participate in the ancillary services market. This has led to the *de facto* exclusion of generation capacity that cannot be programmed to increase or reduce load as required for the performance of ancillary services (essentially certain RES, such as wind or solar).

Another technical performance criterion relates to ramp up times. The Belgian strategic reserve for instance requires a 6.5 hour ramp-up time for participating power plants whilst keeping the door open for even longer ramp-up times if these can be justified by the bidders. The planned Greek flexibility remuneration mechanism (not included in the sector inquiry) grants capacity payments to individual plant capable of increasing electricity generation at a rate greater than 8 MW/min with three hours' notice (starting from hot conditions).

Finally, Member States often **de-rate capacities** to reflect their actual value to supply electricity during scarcity periods, for example taking into account average maintenance needs or average load factor. De-rating is common in market-wide mechanisms including a large variety of capacity providers. De-rating is either determined centrally (as in the Italian and British[86] central buyer mechanisms and the Spanish availability incentive mechanism) or de-centrally by the individual capacity providers subject to *ex-post* control (as in the French de-central obligation scheme). In either case, the capacities will only participate in the mechanism to the de-rated extent. If for example a 400MW power plant is only expected to make 60% of its full installed capacity available on average, it will be able to participate in the capacity mechanism only with up to 240MW).[87]

De-rating is particularly relevant for renewables because of their intermittence. In the French mechanism, renewables producers may opt out of the self-de-rating regime and apply a pre-determined de-rating factor instead. In that case, their risk of penalties for unavailability is reduced because they are only subject to penalties if their unavailability is due to technical reasons (not meteorological reasons).

[85] However, in practice the Belgian tender attracted bids from existing foreign plants which proposed to disconnect from their Member State's grid in order to connect to the Belgian grid and become part of the Belgian TSO's balancing zone (thereby increasing the amount of capacity available to Belgium). To the extent the minimum power plant efficiency requirement or requirement to be able to perform ancillary services had the effect of limiting such foreign offers, they in fact acted as implicit eligibility factors.

[86] Though in the British mechanism capacity providers have limited discretion to choose their de-rating within centrally-determined bands for different technology types.

[87] Note: in the case of self-de-rating, in theory the respective power plant could participate to the capacity mechanism with its full 400MW of installed capacity, but it will then be subject to unavailability penalties in order to discourage overestimating of capacities. The strength of non-performance penalties is therefore particularly important in mechanisms that allow self de-rating.

5.2.2.2 Demand response

Rationale for selectivity

Demand response can reduce peak demand and therefore reduce the overall need for generation and transmission capacity. Moreover, by putting a price on their willingness to reduce demand, demand response providers and aggregators reveal their individual Value of Lost Load, as explained in Chapter 2. The participation of demand response in capacity mechanisms is also of particular importance from a competition perspective since it may foster new entry and help ensure existing capacity providers face competition.

Some Member States target demand response specifically by means of interruptibility mechanisms. Such schemes may be intended to kick-start demand response and unlock its potential, in particular from energy intensive industries.

Openness of capacity mechanisms to demand response

While almost all Member State support demand response by means of some form of capacity remuneration, it does not always compete on equal footing in capacity mechanisms or is even implicitly or explicitly excluded. Even separate interruptibility schemes are not always open to all types of demand response.

<u>Explicit exclusion</u>

Demand response is explicitly excluded from all tenders for new capacity covered by the sector inquiry since these target specifically certain generation technologies. It is equally excluded from all targeted capacity payment schemes subject to the sector inquiry, but is included in the market-wide Irish capacity payment scheme.

Demand response is furthermore excluded from some strategic reserves (Polish cold contingency reserve and German network and capacity reserves) but included in others (Belgium, Denmark and Sweden). In the Belgian and Swedish reserve, demand response is only subject to limited competition from generation since they define a minimum share of demand response. The requirement to contract a minimum amount of demand response results in practice in a separate category of strategic reserve that does not directly compete with generation and therefore does not increase competition in the capacity mechanism. In Belgium the special treatment of demand response was welcomed by demand response aggregators as an efficient way to kick-start their development. In the abandoned Danish strategic reserve, 10% of the total volume required would have been available with a special capacity product to enable competition between demand response and generators.

Market-wide capacity mechanisms almost always encompass demand response. This is true for the current Irish capacity payment scheme and the planned Irish central buyer scheme, but also for the French de-central obligation scheme. The planned Italian central buyer mechanism does currently not allow for the participation of demand response, but Italy plans to include demand response at a later stage.

Conversely, in many Member States, demand response is still targeted specifically through separate mechanisms. This is the case in Germany, Spain, Italy, Ireland Poland and Portugal, where support is granted through a separate strategic reserve type of mechanism only aimed at demand response, commonly referred to as an interruptibility mechanism.

Implicit exclusion

The eligibility of demand response to a capacity mechanism may *de facto* be influenced by the Member State's design choices on the following points:

- size requirements;
- the lead time between capacity contracting and capacity delivery; and
- the product design (and in particular the availability duration, testing and requirement to provide collateral), explained in more detail in sub-section 5.4.2.1.

As mentioned above in sub-section 5.2.2.1, some schemes may limit participation to capacity exceeding a certain **size**. If the size threshold is set too high, this may present a barrier to entry to smaller demand response providers, particularly if aggregation is not allowed. A number of interruptibility schemes targeting demand response services set such thresholds. For example, in the existing German interruptibility scheme a 50 MW threshold applies, although aggregation is possible, while in Spain separate auctions are held for 5 MW and 90 MW loads with no possibility for aggregation.

The **lead time** is the time between the conclusion of the allocation process and the start of the delivery obligation for the successful bidders.

In the originally planned strategic reserve for Denmark, the lead time was only about one month, while in Sweden it appears to have been around 11 months for generation and 2.5 months for demand response in the most recent tenders for delivery in winter 2015/16. 40% of market participants in Belgium considered that the two-month lead time was insufficient for the sourcing of demand response. This concern was voiced also by respondents in Denmark. However, in all strategic reserves in which demand response can participate, the lead time is the same for demand response and generation. These reserves have also in practice succeeded in attracting some demand response capacity which proved reliable when activated. In interruptibility schemes, the lead time varies from one month to 3 years. Irrespective of the lead time, the duration of the scheme as such is considered important for the participation of demand response operators.

Under the French de-central obligation scheme, demand response providers will be able to carry out the certification process from four years up to two months prior to the start of the delivery obligation, while a minimum three-year lead time is provided for existing generation. Furthermore, participants in the mechanism will be able to adjust their position at any time before the delivery period and even after the delivery period. Market participants welcomed the flexible lead time envisaged for demand response and the possibility of continuously trading capacity certificates as it would facilitate their participation.

Market participants in Italy expressed the view that the four-year lead time proposed for the planned central buyer mechanism would be too long for demand response providers, who would not be able to commit too long in advance of the delivery period. The British capacity mechanism includes a one year ahead auction in addition to the main four year ahead auction, which was particularly intended to help enable demand response participation.

As regards **product requirements**, their impact is illustrated for example by the experience with the Polish interruptibility scheme. The first auction organised by the Polish TSO for the procurement of interruptible load was postponed as no offers were received. Subsequent auction rounds with less strict participation conditions were able to attract only limited amounts of interruptible capacity (up to around 200MW of capacity after a total of five auction rounds spread over four years). According to market participants, the potential for interruptible load services in Poland is much bigger and one of the reasons why the auction did not manage to unlock the full potential of demand response has to do with the products requirement (the baseline methodology is unclear so demand response providers find it difficult to identify the actual demand reduction obligation) and the level of remuneration offered (payment for actual interruptions without availability payments).

5.2.2.3 Storage

The sector inquiry found no capacity payments dedicated solely to storage capacities. The four market-wide capacity mechanisms covered by the sector inquiry, the existing Irish capacity payment scheme, the planned Irish and Italian central buyer schemes and the French de-central obligation scheme, all appear to be open to storage. In the case of the German network reserve and the abandoned Danish strategic reserve storage was eligible to participate.

5.2.2.4 New vs. existing capacities

Rationale for selectivity

With respect to the inclusion of new and existing capacities, the sector inquiry has shown that the focus of Member States is often either entirely on attracting new capacity or on avoiding the closure of existing capacity, rather than both. The capacity mechanisms are therefore often tailored entirely to address either of those problems. At one end there is the tender for new capacity, aiming to attract new capacity only, while at the other end there is the strategic reserve aimed at keeping plants that were announced for closure or mothballing available to the system.

Openness of capacity mechanisms to new and existing capacities

<u>Explicit exclusion</u>

In four Member States (Belgium, France, Portugal and Spain), separate capacity schemes for new and existing capacity providers co-exist or are planned.[88]

In the three tenders for new capacity identified as part of the sector inquiry (the abandoned tender in Belgium and the ones in Ireland and Brittany), contracts were offered to new generation capacity only. Existing capacity would receive no remuneration.

None of the strategic reserves covered by the sector inquiry explicitly excluded new capacity. Equally in the central buyer models in Britain and being developed in Ireland and Italy both existing and new capacity can participate. The same is true for the French de-central obligation scheme, where both new-build generation capacity and existing capacity can be certified and consequently receive tradable certificates.

Capacity payment mechanisms are almost always open to both new and existing capacities. In certain cases, however, capacity payment mechanisms may be specifically targeted at new-build capacity. This is for instance true for the Spanish and Portuguese investment incentive mechanisms.

<u>Implicit exclusion</u>

Even in cases where both new and generation capacity can theoretically compete, either of them can *de facto* be excluded by:

- lead time;
- contract duration; or
- specific prequalification requirements.

The concept of **lead time** is not applicable to the capacity payment mechanisms covered by the sector inquiry because there is no time gap between the allocation and the delivery obligation. This is because in this kind of mechanism, capacity providers are either automatically selected or are selected upon the submission of a simple application form, as long as they fulfil the eligibility criteria. Table 8 below provides an overview of the lead time in the remaining capacity mechanisms.

[88] In the case of Belgium, a tender for new capacity was envisaged alongside the strategic reserve but was later abandoned.

Table 8: Lead time in the capacity mechanisms covered by the sector inquiry

Member State	Capacity mechanism	Lead time *
	Tender for new capacity	
Belgium	Tender for new capacity	Proposed by tenderers
France	Tender for new capacity in Brittany	Proposed by tenderers
Ireland	Tender for new capacity	3 years
	Strategic reserve	
Belgium	Strategic reserve	~ 2 months
Denmark	Strategic reserve	1 month
Germany	Network reserve- mandatory	1 year**
	Network reserve - voluntary	4.5 months
	Capacity reserve	Not yet known
Poland	Cold contingency reserve	~ 2 years
Sweden	Strategic reserve - generation	8-11 months
	Strategic reserve -demand response	2.5 months
	Interruptibility services scheme	
Germany	Interruptibility scheme	2 weeks
Italy	Interruptibility scheme for Sardinia and Sicily	3 years
	Interruptibility scheme for the mainland	3 years to 1 month
Poland	Interruptibility scheme	Not available
Portugal	Interruptibility scheme	Not applicable*
Spain	Interruptibility scheme	~ 4 months
	Central buyer mechanism	
Ireland	Planned central buyer mechanism	Not yet known
Italy	Planned central buyer mechanism	4 years
	Decentralised mechanism	
France	Supplier obligation- existing generation	4 to 3 years
	Supplier obligation - new generation	4 years to 2 months
	Supplier obligation -demand response	4 years to 2 months
** The concept of lead time is not applicable to capacity payments*		
***Planned closure must be announced 12 months ahead*		

Source: European Commission based on replies to sector inquiry

It appears from Table 8 that strategic reserves tend to have shorter lead times than the other volume-based mechanisms. Despite in theory being open to new and existing generation capacity, they managed to attract only existing generation.

40% of market participants in Belgium believe that the two-month lead time is insufficient to carry out the technical investments needed to bring the selected installations in line with the requirements of the strategic reserve.

In Ireland, the tender for new capacity was launched in 2003 and became operational by the planned deadline in 2006. The lead time for the tenders for new capacity in Belgium and France was not set in advance but had to be proposed by tenderers and was evaluated as part of the award criteria. In the French tender, the regulatory authority (CRE) expressed reservations about the proposed timeframe for completion of the project by the successful bidder.

A lead time of four years for both new and existing capacity applies in the British central buyer mechanism and is envisaged in the Italian one. The British 2014 and 2015 four year ahead auctions managed to attract about 2,621 MW and 1,936 MW of new generation capacity, respectively.[89] Furthermore, under the British central buyer mechanism an additional auction is held one year ahead of delivery, while the Italian mechanism provides for adjustment auctions and secondary trading of reliability obligations.[90]

Conversely, under the French de-central obligation scheme, different lead times are envisaged for new and existing capacity. The latter must be certified between three and four years ahead of the delivery year while new generation capacity (like demand response) can be certified up to two months prior to delivery. It is noteworthy that capacity certificates can be traded for the whole duration of the lead period.

The vast majority of market participants in France and Italy consider the lead time appropriate to allow the participation of new generation capacity provided that the necessary authorisations and permits have already been obtained at the time of the capacity allocation. However, market participants in France pointed out that the mechanism, which is in principle based on bilateral trading, will be successful in triggering new investments only if clear price signals are provided at the beginning of the lead period.

The length of the contracts concluded under the capacity mechanisms is also essential to determine the competition between new and existing capacity. Table 9 below provides an overview of the **duration of contracts or certificates** in the capacity mechanisms covered by the inquiry.

[89] The total capacity purchased amounts approximatively to 49,259 MW in 2014 and 46,354 MW in 2015. See National Grid, Final Auction Results, T-4 Capacity Market Auction 2014, available at: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf; and National Grid, Provisional Auction Results, T-4 Capacity Market Auction 2015, available at https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/2015%20T-4%20Capacity%20Market%20Provisional%20Results.pdf

[90] In the Italian central buyer mechanism the main auction (T-4) will be followed by yearly adjustment auctions with the aim of enabling capacity providers to re-negotiate the contracted obligations and the TSO to adjust the amount of capacity to be procured in concomitance with the approaching of the delivery period. Hence, for these auctions the lead time varies from three to one year. Furthermore, participants will be able to further adjust their position through continuous trading in the secondary market during the period from the adjustment auction and the delivery period.

Table 9: Contract length in the capacity mechanisms covered by the sector inquiry

Member State	Capacity mechanism	Contract length
	Tender for new capacity	
Belgium	Tender for new capacity	6 years
France	Tender for new capacity in Brittany	20 years
Ireland	Tender for new capacity	10 years
	Targeted capacity payments	
Italy	Targeted capacity payments	1 year
Spain	Availability incentive	1 year
	Investment incentive	20 years *
	Environmental incentive	10 years
	Supply guarantee constraints resolution	4 years
Poland	Operational reserve	Indefinite duration
Portugal	Availability incentive	Operational license period of the plant
	Investment incentive	10 years
	Strategic reserve	
Belgium	Strategic reserve - generation	2-3 years
	Strategic reserve - demand	1 year
Denmark	Strategic reserve	3 years
Germany	Network reserve - final closure	2 years
	Network reserve - preliminary closure	up to 5 years
	Capacity reserve - existing generation	2 years
	Capacity reserve - new generation	15 years
Poland	Cold contingency reserve	2 years (with possible extension of another 2 years)
Sweden	Strategic reserve	1-2 years
	Interruptibility services scheme	
Germany	Interruptibility scheme	1 month**
Italy	Interruptibility scheme for Sardinia and Sicily	3 years - contracts negotiated each month on a rolling basis
	Interruptibility scheme for the mainland	3 years to 1 month
Spain	Interruptibility scheme	1 year
Poland	Interruptibility scheme	Not available
Portugal	Interruptibility scheme	1 year
	Central buyer mechanism	
Ireland	Planned central buyer mechanism	Possible different options - up to 15 years
Italy	Planned central buyer mechanism	3 years
	Decentralised mechanism	
France	Supplier obligation	1 year
	Market-wide capacity payments	
Ireland	Market-wide capacity payments	Indefinite duration - remuneration recalculated periodically
** The contract length under the investment incentive scheme was 10 years until 2011*		
*** Germany has proposed to shorten the contract length to one week in the future*		

Source: European Commission based on replies to sector inquiry[91]

In strategic reserves open to both new and existing generation capacity, the contract length is the same for both and ranges from 1 to 3 years. An exception is the German network reserve that allows for contracts of up to 5 years. In any event, these strategic reserves have managed to attract only existing generation capacity (and in some cases demand response). Market participants consistently expressed the opinion that strategic reserves are not fit to promote

[91] Plants in the German network reserve can be forced to remain in the network reserve beyond the indicated contract lengths of 2 and 5 years so long as the relevant TSO continues to consider them 'system relevant'.

investments in new capacity. Moreover, several market participants have argued that one and two-year contracts may not be sufficient to refurbish existing generation units.

In the case of the inquired capacity payment mechanisms open to both new and existing capacity, the duration of contracts is one year. An exception is the Portuguese availability incentive payment scheme which grants the payments for the entire operational lifetime of new plants and for the remaining lifetime of existing plants. With respect to the duration of the payment schemes as such, it is indefinite in Italy and Portugal, while it is limited to 10 years in Ireland and one year in Spain. According to the Irish authorities, the mechanism has managed to attract investments in generation, demand response and storage since its introduction in 2007. On the other hand, market participants from those countries where the duration of the mechanisms is short (Spain) or the level of remuneration has varied significantly over time (Spain and Portugal) are of the view that the mechanism mainly aims at preventing existing generation from exiting the market. They have also noted that the changes in the level of remuneration create uncertainty and undermine signals for investments.

In the French de-central obligation scheme and the planned Irish and Italian central buyer mechanisms, the contract length is the same for new and existing generators. In France, one-year contracts were considered sufficient to address the missing money problem for existing generators and other capacity providers, but market participant respondents stated that the mechanism would not attract investments in new capacity. As for the planned Italian capacity mechanism, market participants are generally of the view that contracts of three-year duration may be sufficient to attract investments in new generation capacity. Others however pointed out that this duration is only sufficient to avoid mothballing which would be the objective of the mechanism given that most CCGT units in Italy are new and efficient.

The British capacity mechanism is the only one among those open to new and existing capacity where the contract lengths differ for new and existing generators. The 2014 and 2015 auctions attracted approximatively 2,621 MW and 1,936 MW of new generation capacity, respectively. In 2014, 92% of the new generation capacity was awarded long term (14 and 15 year) contracts (2,423 MW), while in 2015 only 50% (982.50 MW) of new-build generation chose those types of contracts.[92]

Likewise, all three tenders for new capacity (Belgium, France and Ireland) offer longer contract durations ranging from 6 to 20 years. In Spain, 20 year contracts are available under the investment incentive capacity payment scheme. In Portugal, where 10-year contracts are

[92] See National Grid, Final Auction Results, T-4 Capacity Market Auction 2014, available at: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf; and National Grid, Final Auction Results, T-4 Capacity Market Auction for 2019/2020, available at: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20Final%20Results%202015.pdf

allocated for the construction of new hydroelectric installations[93], installed hydro capacity is expected to increase from 5.6 GW in 2014 to 7.9 GW in 2020.

Additionally, in strategic reserves, new generation capacity is often implicitly excluded through **preselection criteria**, such as the 15 months prior announcement for closure in the Belgian strategic reserve, the requirement for plants to derogate from emission standards under the IED in Poland or the requirement for plants not to return to the market once they have entered the reserve in Germany. In all these cases, new generation capacities are therefore effectively excluded or strongly discouraged from participating.

5.2.2.5 Locational requirements within the Member State

Rationale for location requirements within the Member State

One main reason to include locational capacity requirements in a capacity mechanism is to take account of network constraints and ensure capacity is built or maintained in particular places.

Locational requirements in capacity mechanisms

The capacity mechanisms covered by the inquiry are in general open to capacity irrespective of its location within the Member State although separate rules often apply to islands.[94]

Exceptions are the tender for new capacity in Brittany and the Italian central buyer mechanism where participation is linked to the location of the capacity provider in a certain region within the Member State. The abandoned Danish strategic reserve, the German network reserve and the Swedish reserve also have locational requirements.

Explicit exclusion

Explicit locational eligibility requirements can be found in the tender for new capacity in Brittany, given that the new power plant must be built in a certain area of Brittany. In the Swedish reserve, only capacity located in South-Sweden can be contracted while the abandoned Danish reserve was intended to contract only capacity located in East-Denmark. Furthermore, the central buyer mechanism in Italy envisages zonal capacity auctions.

Implicit exclusion

Implicit locational requirements are to be found in the 'mandatory part' of Germany's network reserve, which is *de facto* restricted to generators located in South-Germany.

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[93] Note: in this Portuguese investment incentive scheme for hydro power plants, 10 year contracts are equally granted for the repowering of existing plants, in order to extend their lifetime.

[94] Participation in capacity mechanisms in Portugal and France is limited to capacity providers located on the mainland, while the British capacity mechanism excludes capacity providers located in Northern Ireland. Moreover, Italy has separate interruptibility auctions for Sardinia and Sicily.

5.2.2.6 Cross-border locational requirements

Rationale for excluding cross-border participation

Member States mostly limit participation in the mechanism to capacity located in their territory, citing various reasons mostly based around the relative lack of control their TSOs have over foreign capacity and the inability to ensure imports when they might need them without reserving interconnector capacity for this purpose – which would undermine the efficiency of the internal market by reducing the interconnection available to traders.

Table 10: Approach to cross-border participation in the capacity mechanisms in sector inquiry countries

Member State	Capacity mechanism	Approach	Member State's rationale for approach
Belgium	Tender for new capacity	Foreign plants were allowed to bid if they committed to develop a transmission connection to the Belgian grid and become part of the Belgian bidding zone.	
	Strategic reserve	Expected imports are taken into account when calculating the amount of capacity to contract. No direct participation or remuneration for foreign capacity.	Direct participation would require reservation of interconnection capacity which would reduce the efficiency of market coupling. Without reservation of interconnection, foreign capacity would not be sufficiently reliable.
Denmark	Strategic reserve	Expected imports taken into account when calculating demand. No direct participation or remuneration for foreign capacity (or of capacity in West Denmark).	Imports are already assumed so there would be no additional security of supply benefit to Denmark of contractin foreign capacity.
Italy	Central buyer	Interconnections will be taken into account implicitly (added as zero bids to the demand curve). Direct participation in the central buyer mechanism is being considered for the future.	
Ireland	Tender for new capacity	The 2003 tender for new capacity was open to foreign generators insofar as they could demonstrate their ability to deliver in Ireland.	
	Market wide capacity payment	Levies a MWh charge on exports and adds a MWh capacity payment on imports (though this will no longer be possible once market coupling is implemented).	
	Central buyer	Developing options for direct participation of foreign capacity and/or interconnectors.	
France	Tender for new capacity	Limited to capacity within Brittany.	
	De-central obligation	Currently, supplier's obligations are reduced to account for expected imports. Developing options for direct participation of foreign capacity and/or interconnectors.	Difficult to certify, control and monitor foreign capacity. Difficult to apply penalties to foreign capacity. Difficult to design an allocation process to identify the foreign capacity that should receive certificates. Particularly challenging to enable cross border demand response where neighbouring countries do not have the s market access for demand response as France. Difficult to identify the boundary for participation – e.g. should it just be the neighbouring zones, or more remote zones? Coordination needed to prevent double counting capacity.
Germany*	Strategic reserve (network reserve)	The participation of plants in other countries is possible in the current network reserve.	
	Strategic reserve (capacity reserve)	The first plans on future country-wide capacity reserve make it clear that foreign participation is not planned to participate.	Interconnections should participate in the market - interconnector capacity should not be reserved outside the market.
Poland	Strategic reserve	No foreign participation possible. Not clear whether foreign capacity is taken into account for setting volume.	Units held in reserve must be able to be dispatched by the Polish TSO. This is not possible for capacity in neighbouring zones.
Portugal	All	Interconnection not taken into account and foreign capacity cannot participate.	Units held in reserve must be able to be dispatched by the Polish TSO. This is not possible for capacity in neighbouring zones.
Spain	All	Interconnection not taken into account and foreign capacity cannot participate.	Imports were considered unreliable when the mechanism was last reviewed in 2007. For the future, concerns relate to the difficulty in ensuring imports to Spain when needed, and the possibility for neighbouring TSOs to curtail exports in a period of concurrent scarcity.
Sweden	Strategic reserve	No direct participation or remuneration for foreign capacity. The expected level of imports does not appear to have been taken into account when setting the amount of capacity to include in the reserve.	Direct participation would require reservation of interconnection capacity which would reduce the efficiency of market coupling.

* Please note that these responses are the Commission's preliminary assessment of the current and future German reserves. The German authorities have not provided information on these reserves in the inquiry because Germany does not regard the existing network reserve as a capacity mechanism and because plans on the future reserve were still immature at the time the questionnaires were responded to.

Source: European Commission based on replies to sector inquiry

Openness of capacity mechanisms to foreign capacities

Table 10 shows the current approaches taken with regard to foreign capacity in the Member States included in the sector inquiry, based on information provided by public body respondents. Since all of the existing mechanisms covered by the inquiry either explicitly include or exclude foreign capacity, this subsection will not make a distinction between explicit and implicit exclusion.

Portugal, Spain and Sweden appear to take no account of imports when setting the amount of capacity to support domestically through their capacity mechanisms. In Belgium, Denmark, France and Italy, expected imports are reflected in reduced domestic demand in the capacity mechanisms. The only Member States that have allowed the direct participation of cross-border capacity in capacity mechanisms are Belgium, Germany and Ireland.

Foreign plants were allowed to participate in the Belgian tender for new capacity, provided that they would subsequently become part of the Belgian bidding zone even if geographically located in another Member State.

In the Irish tender, foreign capacity could participate if it could demonstrate its contribution to Irish security of supply – no foreign capacity was selected in the tender. In the existing Irish capacity payments model, foreign capacity can benefit from capacity payments. However, the method for enabling this participation involves levies and premiums on electricity prices and is not therefore compatible with market coupling rules which require electricity prices, not capacity premiums/taxes, to provide the signal for imports and exports.[95]

None of the strategic reserves are open to generators located outside of the Member State operating the reserve, except for the German network reserve which contracts capacity outside of Germany provided that it can contribute to alleviating security of supply problems in Southern Germany through re-dispatch abroad.

A condition of the State aid approval for the British capacity mechanism was that the participation of interconnected capacity would be enabled. Since December 2015 the British capacity mechanism has included interconnectors with Britain, which can participate as price takers (i.e. they cannot bid above a predetermined threshold without having to justify the need for that higher support) in capacity auctions. Interconnectors receive one year capacity agreements at the auction clearing price, in return for a capacity obligation requiring the delivery of capacity towards Britain at times of scarcity.

Despite the current general lack of meaningful foreign participation, many Member States are trying to develop cross-border participation in their mechanisms. France

[95] Note however that the Irish capacity mechanism does operate across the UK and Irish border because of joint market arrangements and a single bidding zone covering Ireland and Northern Ireland.

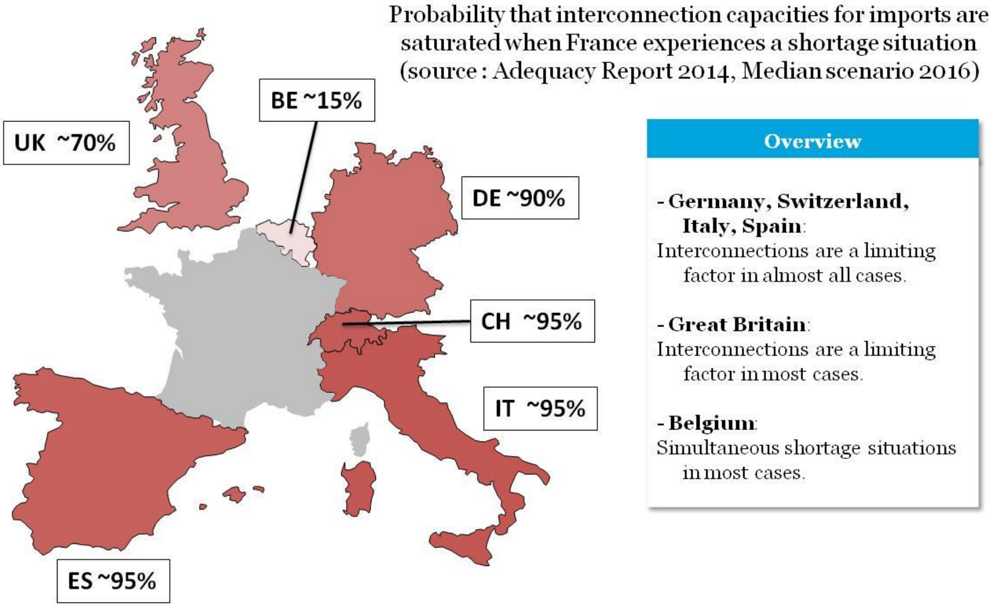
carried out last year a consultation which outlined different options for the participation of interconnectors or foreign capacity in the de-central obligation scheme. Ireland published a consultation in December[96] on options for cross-border participation in its planned mechanism. Italy is apparently considering future foreign participation in its capacity mechanism.

Openness of capacity mechanisms to foreign capacities

The contribution foreign capacity makes to a neighbour's security of supply is provided partly by the foreign generators or demand response providers that deliver electricity, and partly by the transmission (interconnection) allowing power to flow across borders. Depending on the border, there can be a relative scarcity of either interconnection or foreign capacity.

In its 24 September consultation on options for cross border participation in the French de-central obligation scheme, RTE included analysis of the extent to which interconnection with its neighbours is a limiting factor to receiving imports at times of scarcity in France. In only 15% of scarcity situations in France, interconnectors between Belgium and France are congested (i.e. there is no more capacity available to transfer electricity from Belgium to France). But in 95% of scarcity situations in France, interconnectors between France and Spain, France and Switzerland, and France and Italy are congested.

Figure 25: Probability that interconnectors are congested at times of stress in France



Source: RTE Consultation on cross-border participation

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[96] http://www.semcommittee.eu/en/wholesale_overview.aspx?article=f254d505-16bc-4a66-b940-bf2cc7b614ae

RTE's analysis shows that while there may be a relatively strong security of supply benefit to France of increased investment in generation and demand response capacity in Belgium, there is likely to be relatively little security of supply benefit to France of increased investment in generation or demand response capacity in Spain, Switzerland or Italy; on those borders, France would see increased security of supply from increased investment in interconnection.

This complicates the design of an efficient solution for enabling cross border participation in capacity mechanisms since it requires an appropriate split of capacity remuneration between interconnector and foreign capacity to reflect the relative scarcity of each. It also ideally requires this split to adapt over time – for example through a design that increases the reward for foreign capacity and reduces the reward for interconnection if over time the proportion of interconnection increases.[97]

5.2.3 Issues encountered in relation to eligibility

5.2.3.1 Despite trend towards opening, high selectivity of existing capacity mechanisms

The findings on the various capacity mechanisms indicate that most mechanisms are still targeted at a limited range of capacity providers. The sector inquiry shows that implicit participation requirements are not only as frequent as explicit ones, they are also equally effective in reducing the range of eligible capacity providers.

There is however a growing tendency towards more encompassing mechanisms. This trend is illustrated by the recent British central buyer mechanism, the de-central supplier obligation scheme in France, the planned central buyer scheme in Ireland and, so far to a lesser degree, by the mechanism being developed in Italy which for the time being excluded demand response.

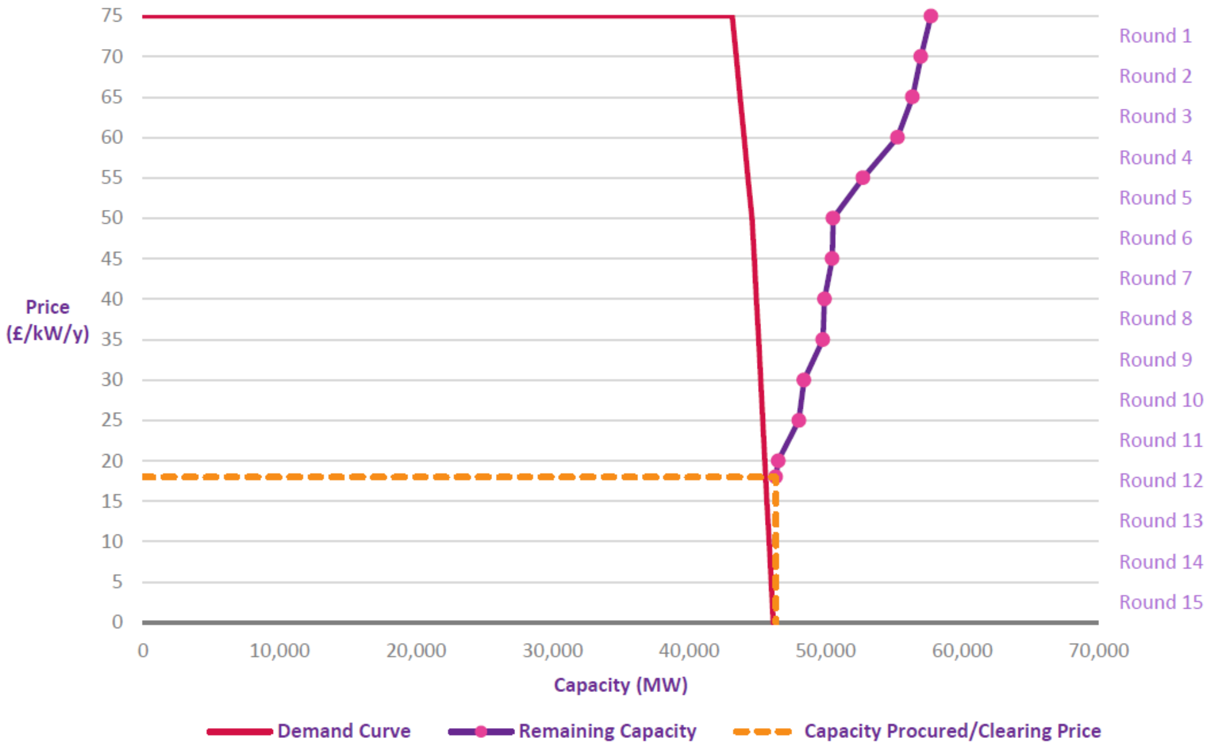
5.2.3.2 Selectivity leads to less competition

Eligibility criteria are of particular importance from a competition perspective. If allowing for a wide participation, a competitive bidding process allows the market to bring forward the technologies that can most cost-efficiently provide the required capacity. Competitive pressure should provide capacity providers with incentives to bid at the level that corresponds to the funding they require to provide the necessary capacity product.

[97] In the framework if its market design initiative, the Commission is working on a detailed regulatory solution to organise cross-border participation in capacity mechanisms.

The supply curve in the most recent British capacity auction (see Figure 26) and the mix of different capacity types selected in the auction (see Figure 27) show that extending the pool of eligible capacities leads to a lowering of the price paid for capacity.[98]

Figure 26: British Capacity Market 2015 auction supply curve



Source: National Grid[99]

In the 2015 British capacity auction 46.35 GW of capacity was contracted to the different types of capacity included in the left hand pie chart of Figure 27, whereas 11.37 GW of different capacity types participating to the auction did not receive contracts (see the pie chart at the right hand side of Figure 27). In this case, the exclusion of storage capacity, for instance, would have required the procurement of 2,617 MW of other, more expensive (since not selected) types of capacity. In other words, less competition for the capacity contract would have led to a higher overall capacity price and, *a contrario*, increased competition leads to lower capacity prices. By opening up the pool of eligible resources as much as possible without jeopardising the objective of the mechanism, Member States can therefore attain security of supply at a lower price.

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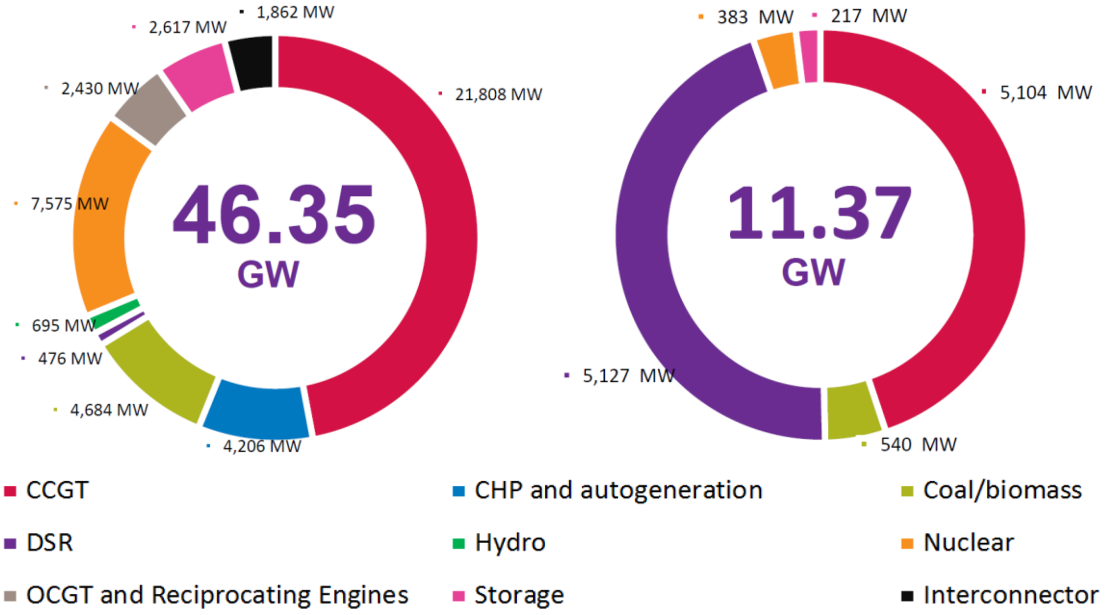
[98] Note if demand is reduced to account for excluded capacity then the price paid for capacity may also reduce. However, if capacity is excluded there is less certainty about whether it will actually be available in the delivery year. Any exclusion also reduces the potential for new entry, which will help increase competition and exert downward pressure on prices.

[99] National Grid - Final Auction Results T-4 Capacity Market Auction for 2019/20. Full report available here: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20Final%20Results%202015.pdf

Figure 27: Results of 2015 T-4 British capacity auction; left: capacity providers contracted; right: non-selected capacity providers



Source: National Grid[100]

5.2.3.3 Non-competitive interruptibility schemes may result in overcompensation of industry

There is a risk that interruptibility schemes are not competitive (for instance because of high participation thresholds, as described in sub-section 5.2.2.2) and overcompensate participating industries. A reason is that it is difficult for governments to estimate the actual costs of load reductions or load-shifting. Some of these mechanisms were indeed criticized by respondents to the sector inquiry as constituting indirect subsidies to energy intensive industries. This was particularly the case for interruptibility mechanisms that were in practice hardly ever used (for instance in Portugal and Spain) or where the remuneration level was much higher than the one paid to generators under another capacity mechanism (as in Italy). In Poland, in contrast, the demand response-specific capacity mechanism remunerated demand only if actual curtailments were carried out by the TSO (i.e. per MWh payments instead of per MW payments). Moreover, during actual scarcity periods, the TSO curtailed demand administratively (without remuneration) rather than through the mechanism.

5.2.3.4 Selectivity leads to a snowball effect

The selective remuneration of certain types of capacity only will aggravate the missing money problem of non-remunerated types of capacity and more often than not eventually require the development of additional support measures targeted at those capacity types.

[100] *Ibid.*

This is best illustrated by way of an example. A good example is the fragmented landscape of capacity payment mechanisms in Spain. As early as in 1997 Spanish power plants started receiving targeted capacity remuneration. This however did not appear sufficient to address the generation adequacy problems, since in 2007 the scheme was complemented by an interruptibility scheme and later still, in 2010, by a preferential dispatch scheme for indigenous sources (coal).[101]

Another example is the tender for new capacity that is conceived as an emergency response to a perceived urgent need for new generation capacity which the market does not bring forward. If this is indeed the objective of the tender, and it is not accompanied by energy market improvements, it ignores the reasons why the market fails to make the investment decision on its own initiative. If market participants are not confident that the investment will generate a positive return on investment and therefore fail to make new investments, this may indicate that there is a general missing money problem in the market, such that market conditions are already negative for existing plants. The addition of a subsidized power plant to the merit order would only aggravate that situation. In other words, the addition of new generation capacity would only aggravate the missing money problem of existing capacity. This was evidenced by the information received by the Commission when Belgium intended to develop a tender for new gas-fired production capacity, which was argued to further deteriorate the already negative business models of existing gas-fired power plants. It is then only a matter of time until either a solution for the missing money problem of the existing plants imposes itself or the need for another tender or capacity mechanism arises (as a result of existing capacity closing or mothballing). Indeed, in all cases where a tender was launched, it was accompanied or followed by another mechanism.[102]

5.2.3.5 Capacity mechanisms do not address causes of locational capacity issues

Where there is a locational capacity problem (i.e. there is either not enough generation capacity located in that particular region or that region is poorly connected to neighbouring regions), this is a sign that the electricity market is failing to provide the required signals for investment in the right places, or for sufficient transmission investments to mitigate any locational problem.

The sector inquiry has found two types of capacity mechanisms that have selective locational requirements within a Member State's territory:

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[101] In order to obtain sufficient running hours to make the selected coal plants viable, under that scheme the selected coal plants are dispatched prior to other plants, even if these other plants have placed a lower bid in the market.

[102] For France, the tender was accompanied by the de-central obligation mechanism, for Ireland, the tender was followed by a market-wide capacity payment mechanism and in Belgium the tender was launched while in parallel a strategic reserve was developed.

(i) those that correspond to bidding zones, such as the Swedish and abandoned Danish reserve which only procure capacity in specific parts of the country, and the Italian central buyer mechanism which is country-wide but sets different demand levels for different bidding zones; and

(ii) those that are intended to encourage investment in particular locations within large bidding zones, for example the Brittany tender and German network reserve.

All of these mechanisms can maintain or obtain more capacity in a specific region. However, the reserves may not be appropriate in the longer term because their aim is generally to keep existing capacity from mothballing or closing and not to enable new investments. Similarly, tenders can provide a quick-fix solution for a lack of investment in a certain region, but they will have to be accompanied by other measures aimed at improving local investment signals to avoid the need for another tender in the future. Only the Italian central buyer mechanism appears to have the potential to address the underlying market failures preventing investment in a particular region in the longer term by allowing the corresponding regional electricity and capacity prices in Italy's bidding zones to provide suitable investment signals.

5.2.3.6 The exclusion of foreign capacity distorts the Internal Energy Market

The exclusion of foreign capacity from capacity mechanisms reduces the efficiency of the internal market and increases costs for consumers. The most damage is done if Member States make no assessment of the possibility of imports when setting the amount of capacity to contract through a capacity mechanism (in a volume-based model) or setting the price required to bring forward the required volume (in a price-based mechanism). This approach will lead to overcapacity in the capacity mechanism country, and if each country has a capacity mechanism and does the same thing, overcapacity throughout Europe. The potential unnecessary costs of this overcapacity have been estimated at up to EUR 7.5bn per year in the period 2015-2030.[103]

As shown in Table 10 above, some Member States have recognised this problem and attempted to address it by taking account of expected imports (at times of scarcity) when setting the volume to contract in their capacity mechanism. But although this approach recognises the value to security of supply of connections with the internal energy market and reduces the risk of domestic over-procurement it does not address two further ways in which the exclusion of foreign capacity from capacity mechanisms can have distortive impacts across border:

(i) If only domestic capacity receives capacity payments, there will be a greater incentive for domestic investment than investment in foreign capacity or

[103] See Booz & Co, 2013, 'Study on the benefits of an integrated European energy market': https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf

interconnectors. Signals for investment will therefore be skewed in favour of the capacity mechanism zone and there will be less than optimal investment in foreign capacity and in interconnector capacity.

(ii) If capacity mechanisms provide incentives for short term operation on top of the electricity price signal (through capacity obligations and penalties) they will reduce the potential effectiveness of the electricity price as a signal for efficient short term market operation, demand response and imports. This is because it would never make sense to have a combination of electricity prices and capacity mechanism penalties providing a stronger short term signal for operation than electricity prices at VOLL, which represents consumers' maximum willingness to pay. This issue is not discussed further here, but is considered in sub-section 5.4.3.3.

5.2.3.7 Split of capacity remuneration between interconnectors and foreign capacity

If a capacity mechanism only rewards interconnection or foreign capacity, it will not fully correct the distortions the capacity mechanism causes to investment incentives. To ensure the right investment incentives, the revenues from the mechanism paid to the interconnector and/or the foreign capacity should reflect the relative contribution each makes to security of supply in the zone operating the capacity mechanism. Where interconnection is relatively scarce but there is ample foreign capacity in a neighbouring zone, the interconnectors should thus receive the majority of capacity remuneration.[104] This would reinforce incentives to invest in additional interconnection, which is the limiting factor in this case. Conversely, where there is ample interconnection but scarcity of foreign capacity, the foreign capacity should receive most of the capacity remuneration. In this case, foreign capacity is the limiting factor that should receive additional incentives.

5.2.3.8 Risk of increasing fragmentation from diverse cross-border solutions

As explained in sub-section 5.2.2.6, some Member States have developed or are attempting to develop solutions to enable cross border participation in their capacity mechanisms – France, Ireland and the UK for example. When developing solutions for explicit participation of interconnectors or foreign capacity to their mechanism, Member States need to address a number of policy considerations. For example, an explicit participation model needs to identify:

[104] For regulated interconnectors, any capacity congestion rents earned would need to be appropriately regulated (eg. refunded to consumers in the connected markets if the interconnector's revenues – including the capacity revenues – are above its regulated cap). See Regulation 714/2009 Articles 16 and 17.

- whether there should be any restriction on the amount of capacity that can participate from each connected bidding zone – including considering more remotely connected zones;

- what type of capacity product (obligations and penalties) should apply to foreign capacity providers; and

- which foreign capacity providers are eligible to participate – for example whether a mechanism should be open to interconnectors and/or to foreign capacity (demand response, generation, storage).

The risk with an uncoordinated approach is that the internal market becomes increasingly fragmented and complex, with specific different rules emerging on each border.

It is therefore not surprising that 85% of market participant respondents and 75% of public body respondents to the sector inquiry questionnaire felt that rules should be developed at EU level to limit as much as possible any distortive impact of capacity mechanisms on cross national integration of energy markets. As explained in sub-section 5.2.3.6 above, one of the main ways in which capacity mechanisms create distortions cross border is if they are limited to national capacity. The Commission has therefore developed an input paper on a potential approach concerning aspects of cross border participation which is included in Annex 2 for consultation.

5.2.4 Conclusions on eligibility

- To obtain as much competition as possible in the capacity mechanism, Member States should design a mechanism that is as encompassing as possible so that different types of capacity providers are effectively put into competition with each other. This may require specific arrangements to accommodate certain capacity types, the benefit of which should again be balanced against the possible discrimination created by differentiated treatment of different capacity resources.

- Although certain selective capacity mechanisms may appear to be appropriate solutions to address immediate or transitory capacity concerns, in the long run they often do not really target the underlying adequacy problem and even risk aggravating it. They may therefore trigger the need for additional capacity mechanisms to address the fallout of the initial mechanism(s). However, since parallel capacity mechanisms fail to foster competition between different types of capacity providers, they should be avoided as much as possible.

- Unless interconnectors and foreign capacity providers receive remuneration from capacity mechanisms reflecting the extent to which they deliver security of supply for the capacity mechanism zone, signals for investment will be skewed in favour of the capacity mechanism zone and there will be less than optimal investment in foreign capacity and in interconnector capacity. This inefficiency will increase costs for consumers overall.

- Despite the repeated acknowledgement by the European Council of the need for a fully-functioning and interconnected energy market, cross border participation in capacity mechanisms remains rare in practice. There may therefore be a need for a set of principles or rules harmonising the cross-border participation of capacities in different capacity mechanisms, including the definition of a common product to account for the capacity to be supplied from neighbouring markets. Such harmonized approach appears to have the potential to avoid the complexity that might arise if individual solutions are developed for each mechanism or border, while still allowing Member States the flexibility to design different capacity mechanisms to address the problems that best address their local issues.

5.3 Allocation Process

5.3.1 The role of the allocation process in capacity mechanisms

This section covers the 'allocation process', used to select the capacity providers that will receive capacity remuneration and to determine the price paid to these beneficiaries.

The capacity mechanisms covered by the sector inquiry either use an administrative or a competitive allocation process.

When an **administrative allocation process** is employed all the capacity providers that meet the eligibility requirements are selected without competition and the remuneration of capacity is set in advance by the Member State authorities or negotiated bilaterally between the latter and the capacity provider.

In a **competitive allocation process**, eligible capacity providers participate in a bidding process and the capacity remuneration is the result of this process.

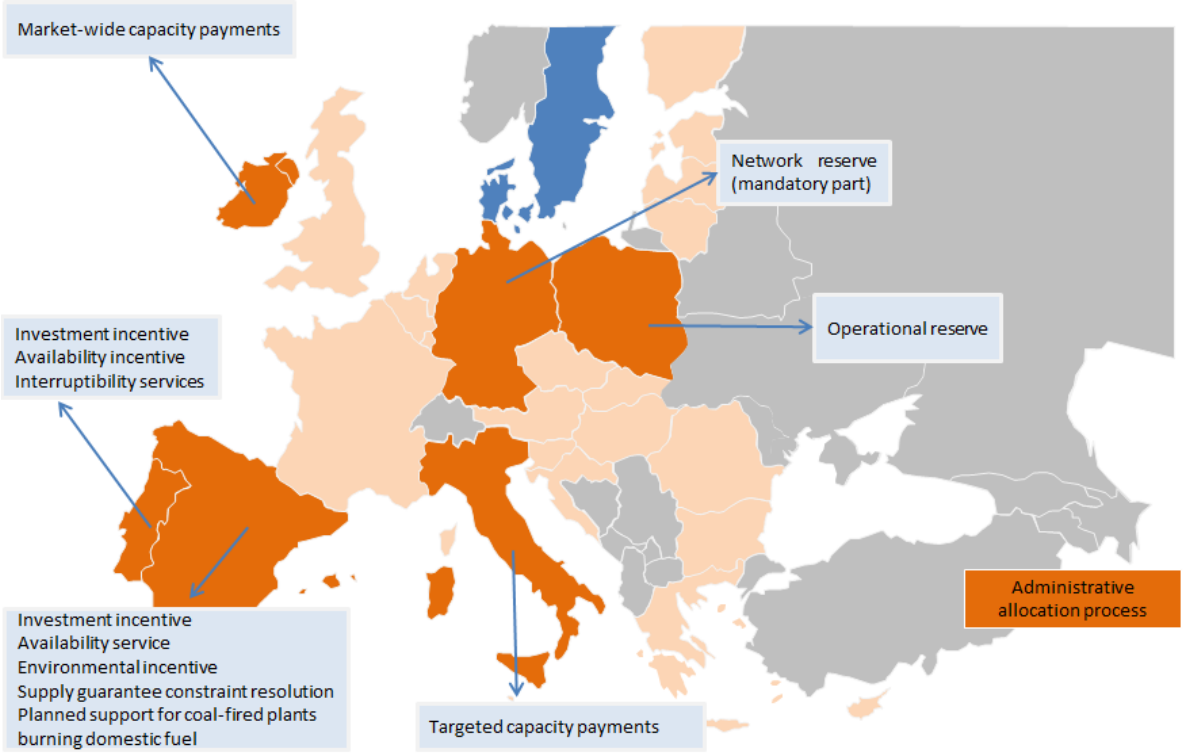
The following sections will examine the design of the different types of allocation processes employed and assess to what extent they prevent excessive profits while sending the right signals for investments.

5.3.2 Findings of the sector inquiry on administrative allocation processes

As illustrated in Figure 28, an administrative allocation process is employed in price-based mechanisms, such as (market-wide and targeted) capacity payment schemes and the interruptibility scheme in Portugal.

Moreover, an administrative procedure is in practice employed also in the 'mandatory part' of the German network reserve. While this reserve is in principle volume-based and the price of capacity is intended to be competitively determined, the requested volume has so far always exceeded the offers of eligible capacity providers. This has resulted in all eligible providers located in Germany receiving the capacity remuneration, which is bilaterally negotiated between the TSO and the capacity providers on the basis of a methodology established by the regulator.

Figure 28: Capacity mechanisms with an administrative allocation process in the Member States covered by the sector inquiry



Source: European Commission based on replies to sector inquiry

In most of these capacity mechanisms, capacity providers submit an application to the competent Member State authority, which limits itself to verifying whether the eligibility criteria are met and the application form is complete. The existing Irish market-wide capacity payment mechanism grants administrative payments systematically to all capacity providers with no need for an application process. A similar process is followed for the operational reserve in Poland where the capacity payment is automatically granted to all available dispatchable plants that were not dispatched by the TSO.

5.3.2.1 Capacity price-setting in administrative allocation processes

In an administrative allocation process, the level of capacity remuneration is established *ex ante* by public authorities rather than being determined by market forces.

In reply to the Commission's survey, the vast majority of market participants have argued that administratively set prices are unlikely to reveal the real value of capacity.

There is one mechanism in which the allocation process has switched from administrative to competitive that is the Spanish interruptibility scheme. This scheme was based on fixed payments until 2014. For each year from 2008 to 2014, the TSO disbursed 550 million EUR to procure 2,000 MW of capacity. In 2015, the TSO decided to allocate the same amount of capacity as in the previous six years by means of an auction rather than an administrative procedure. This resulted in a decrease in the total annual remuneration under the scheme from 550 million EUR to 353 million EUR.

In Germany, the authorities plan to also switch from an administrative to a competitive allocation mechanism for the interruptibility scheme. In order to ensure sufficient competitive tension in the bidding process the total capacity volume to be tendered is planned to be reduced from 3 GW to 1.5 GW.

While the level of remuneration plays an important role in providing signals for investments and ensuring that the right capacity volume is procured to meet a certain reliability standard, only in some price-based mechanisms the level of remuneration (or the methodology for its calculation) is explicitly and automatically tied to the reliability standard., This is the case in the Irish market-wide capacity payment mechanism, the Polish operational reserve and the investment incentive mechanism in Portugal.

In Ireland, the value of the annual capacity payment is determined as the product of the required quantity of capacity (necessary to meet an adequacy standard set for Ireland and Northern-Ireland jointly) and its cost-based price. Furthermore, 40% of the payment is calculated year-ahead, 30% month-ahead and the remaining 30% is determined and allocated *ex-post* so that it reflects the actual value of capacity in any period.

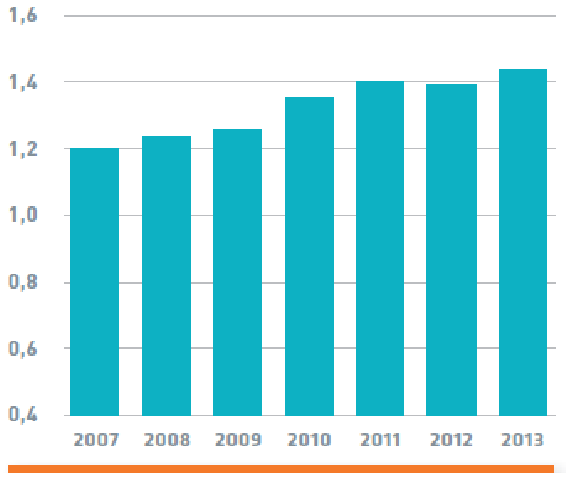
Under the Polish operational reserve the pre-set amount of the payment can be lowered proportionally if the amount of available capacity exceeds the TSO's expectations.

In Portugal, the remuneration under the investment incentive mechanism is inversely proportional to the capacity margin. This means that the remuneration should decrease and eventually tends to zero when the capacity margin has been exceeded so as to avoid that the capacity mechanism sends misleading signals for investment.

In Spain, according to the law establishing the investment incentive mechanism, the remuneration should have been calculated according to a methodology which is almost identical to the one used in the Portuguese investment incentive mechanism. However, that methodology was never applied. Instead, the level of remuneration was administratively set and the payment maintained (and increased for some periods) even in times of overcapacity.

Figure 29 below shows the evolution of the capacity margin in Spain for the period 2007-2014. During the same period, the remuneration under the investment incentives scheme was set at 20,000 EUR/MW in 2007 and at 26,000 EUR/MW in November 2011. It remained more or less stable until July 2013 when the annual payment decreased to 10,000 EUR/MW (however, the aid granting period was doubled at the same time).

Figure 29: Evolution of the capacity margin in Spain



Source: Report on Electric System - year 2013. REE, System Operator

In Spain the capacity margin (ratio between installed firm capacity and peak demand) is set 1,1. The figure shows that this reliability standard was exceeded since as early as 2007. However, the mechanism continued to provide incentives for investments in new capacity. For instance, the sector inquiry identified an example of a new gas-fired power plant which was authorised in 2013 and will receive the investment incentive payments for 20 years once in operation.

Also in Italy, where a reliability standard is set by the TSO, this standard does not seem to be one of the components for establishing the level of payments.

5.3.3 Findings of the sector inquiry on competitive allocation processes

Two different types of competitive allocation processes have been identified in the capacity mechanisms covered by the sector inquiry: central auctions[105] and de-central capacity market systems.

In central auctions, the Member State's authorities determine (or ask the TSO to determine) at the outset the capacity needed to ensure generation adequacy. This capacity is then auctioned. The sector inquiry has also identified a capacity mechanism in which the volume to be procured through the auction is not defined *ex ante*, namely the planned central buyer mechanism in Italy.[106] Auctions have been employed mainly in strategic reserves including interruptibility schemes and for tenders for new capacity. They are also used in central buyer mechanisms.

In the de-central obligation mechanism which France is implementing, the amount of capacity needed to ensure security of supply is not determined *ex ante* but is estimated by

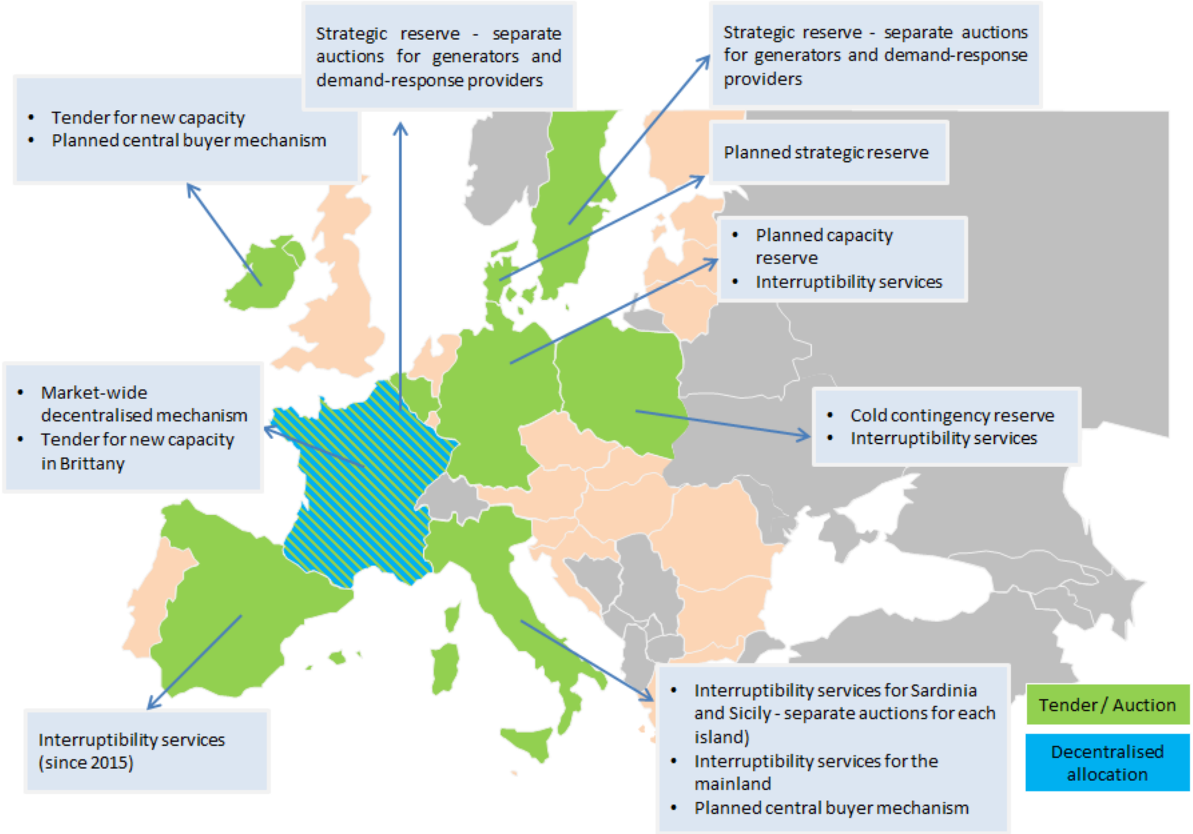
[105] In this report, the term 'auction' is meant to comprise different types of competitive bidding process including also tenders.

[106] Rather than determining a fixed amount of capacity, the planned Italian mechanism uses a sloping demand function so that the capacity to be procured depends also on the prices of the offers in the auction.

individual suppliers. The latter are under the obligation to procure enough capacity to cover the need for their customers from capacity providers.[107]

Figure 30 below provides an overview of the capacity mechanisms covered by the sector inquiry that employ a competitive allocation process.

Figure 30: Capacity mechanisms with a competitive allocation process in the Member States covered by the sector inquiry



Source: European Commission based on replies to sector inquiry

5.3.3.1 Capacity price-setting in competitive allocation processes

The sector inquiry has identified different pricing rules in the capacity mechanisms that employ a competitive allocation process.

Pay-as-bid and pay-as-clear rule

The tenders for strategic reserves in Belgium, Denmark, Germany ('voluntary part' of the network reserve and the planned capacity reserve), Poland (cold contingency reserve)

[107] It is important to note, however, than under the French market-wide capacity mechanisms the estimation of the amount of capacity to be procured is not left entirely to suppliers, since the TSO determines (*ex-post*) the correction factor to be applied to the total consumer demand to simulate severe winter conditions.

and Sweden employ a pay-as-bid rule, meaning that successful bidders receive the remuneration specified in their individual bids.

A pay-as-bid rule was also applied in the tender procedures carried out for the construction and operation of new power plants in Ireland in 2003 and in France in 2012. However, while in the Irish tender the contract was awarded solely on the basis of price, in the tender for new capacity in Belgium and Brittany price was only one of the award criteria (albeit the most important one).

The French de-central obligation scheme envisages the bilateral trading of capacity certificates. However, the power exchange EPEXSPOT has announced that it will create a platform for the trading of such certificates to help increase liquidity and overcome initial uncertainty about the value of capacity.

A pay-as-clear or uniform price rule has been used in the auction in the British central buyer mechanism and is proposed for the planned Italian central buyer mechanism. In this type of auction, successful bidders all receive capacity remuneration equal to the marginal price in the auction (i.e. the most expensive unit that was successful). This means each MW of capacity will receive the same remuneration level at the end of the bidding process.

Price caps and price floors

Existing and planned capacity mechanisms covered by the sector inquiry often include price caps or price floors. Price caps are used in the Italian auctions for the procurement of interruptible load and in the planned Italian central buyer mechanism. In the latter, it is expected that a price cap will be set at the level of the fixed costs of new entrant i.e. the generation technology with the lowest fixed costs. In the British capacity mechanism, the price cap was set at GBP 75,000/MW.

The Belgian strategic reserve and the Polish cold contingency reserve employ an 'implicit' price cap. In Belgium, the national regulatory authority has the power to review the level of the remuneration if it considers bids manifestly unreasonable. In Poland, the 2013 tender for the cold contingency reserve was not successful in procuring the amount of capacity requested because some of the bids exceeded the TSO's projected budget. A second tender procedure in 2014 managed to procure the remainder of the capacity because the bids were substantially lower than in the 2013 procedure.

In the interruptibility scheme for Sardinia and Sicily, where the number of potential participants in the capacity mechanism is limited and the requested capacity risks outweighing supply, bids tend to be submitted close to the price cap. In Spain, the first auction for 2,000 MW of interruptible load in 2015 was followed by an extraordinary auction for an additional 1,020 MW of interruptible load although the service had never been used in the previous six years. The total budget allocated for the services was 550 million EUR. While, as mentioned above, the first auction had succeeded in substantially reducing the cost, with the second auction costs increased to a level close to the total budget available (508 million EUR). Conversely, competition in the two British capacity auctions held to date pushed the clearing price (GBP 19.40/kW/year in 2014 and GBP18/kW/year in 2015) substantially below the price cap, set at GBP 75/kW/year.[108]

A price floor is only envisaged in the Italian central buyer mechanism. According to the Italian authorities, the price floor will enable the capacity mechanism to support new investment without the need for long contracts.

5.3.4 Issues encountered in relation to allocation processes

The choice of the allocation process and its design impact the level of capacity prices and their transparency. These are crucial to ensure that a capacity mechanism sends the appropriate and clear signals for investments. The following sections examine the issues identified in this respect.

5.3.4.1 Competitive allocation processes are better at revealing the real value of capacity

The sector inquiry revealed that the remuneration granted through a competitive allocation process is more likely to correspond to the real value of capacity than where an administrative allocation processes is applied.

This conclusion is supported by a vast majority of market participants from Member States with capacity *payment* mechanisms. For instance, none of the market participants in Spain believe that the level of the remuneration is appropriate in the various price-based schemes. A large majority of market participants in Italy, Portugal and Spain are of the view that the current level of remuneration under the respective capacity payment mechanisms is too low to cover the costs of availability or, in the case of the Portuguese investment incentives mechanism, to recoup the investments for the construction or refurbishment of hydro power plants that the scheme obliges them to undertake.

In capacity payment mechanisms the remuneration is spread over a large number of – in some case all – operators, whereas in an auction the remuneration is granted only to those that are needed to address the estimated capacity shortage. For instance, a number of Italian respondents also noted that although the capacity payment is paid to all eligible capacity providers, the majority of those are never or very rarely called upon to provide their services in situation of system tightness, either because of their location or because of the type of capacity they could supply.

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[108] See National Grid, Final Auction Results, T-4 Capacity Market Auction 2014, available at: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%202014%20Final%20Auction%20Results%20Report.pdf; and National Grid, Final Auction Results, T-4 Capacity Market Auction for 2019/2020, available at: https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20Final%20Results%202015.pdf

In case the remuneration is lower than the real value of capacity the capacity mechanism will not provide adequate incentives for investments and will thus be ineffective. In that case, the capacity mechanism may not deliver value for money as it will not meet the security of supply objective.

However, an administrative allocation process can also set the price at a level that is too high. This was the case for the Spanish interruptibility scheme, where the price per MW of interruptible capacity decreased considerably when the allocation process changed from a fixed remuneration determined *ex-ante* to a competitive auction.

The risk of administratively determining a level of remuneration that is either too high or too low does not occur in competitive allocation processes because the remuneration is based on bids received from market participants that indicate the value they place on delivering the requested service. However, as underlined in the next paragraph, competitive processes need to be well-designed in order to indeed produce a remuneration that reflects the true value of the capacity.

5.3.4.2 The use of a competitive allocation process will not always guarantee competition

Market power can allow capacity providers to withhold capacity or inflate prices in the allocation process. For instance, in the absence of sufficient competition or regulatory oversight, an operator that owns a large fleet of power plants could withdraw some plants from the process to increase competition and the chances of setting higher prices for the plants that it does include in the process. Note strategic withholding is also a risk in electricity markets – it is not a risk unique to capacity mechanisms.

In the auctions held under the interruptible load scheme in Sardinia and Sicily and the second auction held under the Spanish interruptibility mechanisms only few market participants were able to deliver the requested capacity. Those market participants could therefore exercise market power in the auction by bidding close to the price cap (or maximum available budget in the case of Spain). Conversely, the two auctions held so far in the British mechanism demonstrate that when there is strong competitive tension in the allocation process prices tend to be much lower than the price cap.

These examples also show the importance of the design of the competitive allocation process in ensuring that capacity is procured at the lowest cost for the community. This is not the case, for instance, when the amount of capacity to be procured has been overestimated or when the price cap is set at a very high level and there is insufficient competition to determine the right price of capacity.

The issue of market power is even more prominent in de-central allocation systems when these are implemented in a market with a highly concentrated generation segment. Those mechanisms strongly rely on de-central capacity forecasting and trading. Therefore, more established players will normally have an advantage over their competitors as a result of asymmetric market information.

These effects could be partially mitigated by the introduction of mandatory exchange trading in the de-central mechanism. However, only by opening participation to the mechanism as much as possible to new entrants, foreign generation and demand response it can be ensured that competitive pressure is put on the incumbent and that the price of capacity would be the result of competitive market forces. These considerations are valid also for central buyer mechanisms that operate in highly concentrated markets.

When market power exists and it is not possible to extend participation in the mechanisms –due for instance to the poor development of the electricity network or of demand response– an administrative allocation process can be justified with a view to minimise the costs of the system. According to market participant respondents, this logic inspired the German authorities when designing the allocation of the mandatory part of the network reserve.

5.3.4.3 An allocation process that does not identify the real value of capacity sends misleading signals for market entry and market exit

An allocation process that does not reveal the real value of capacity is unlikely to send the proper signals for market entry or market exit.

On the one hand, it can result in artificially keeping existing capacity in the market or even in developing new capacity in situations of overcapacity. This is for instance the case in the Spanish investment incentive mechanism which has incentivised the commissioning of new generation even after the capacity margin had been substantially exceeded.

On the other hand, if the level of remuneration is set too low, it will not provide adequate incentives for keeping plants in the market or for new capacity to enter the market. The vast majority of respondents in the country where a capacity payments mechanism has been established are of the view that the remuneration provided under the mechanism is not sufficient to trigger investments in new generation capacity. Moreover, the vast majority of market participants in Spain believe that the level of remuneration under the availability incentive scheme is not sufficient to recover the costs needed to keep the plants on the market which, however, are prevented from closing by regulation.

Linking the level of remuneration to a reliability standard, as in the Portuguese investment incentive mechanism, can avoid the capacity mechanism sending misleading signals at times of overcapacity, provided that the adequacy standard has been properly defined and the remuneration is amended accordingly. However, the implementation of this solution does not address the issues that arise from not having allowed the level of capacity remuneration to be determined in a competitive manner in the first place.

5.3.4.4 Non-transparent capacity prices can negatively affect investment signals and competition

A low level of transparency characterises those capacity mechanisms where the level of capacity remuneration is bilaterally agreed, such as the French de-central obligation scheme. This lack of transparency can affect investment signals. Some French market participants have expressed this view.

Furthermore, bilateral trading can lead to discriminatory treatment of different capacity providers. The bilateral trading of certificates under the French capacity mechanism tends to favour vertically integrated operators, which can rely on intra-group trading to meet the supplier obligation. This view is supported by several market participants. Mandatory exchange trading of certificates can create a clear price signal. However, given that exchange trading is not compulsory under the French mechanism, a vertically integrated undertaking could still apply more advantageous conditions to its supply branch than to other suppliers.

In Belgium market participants are concerned that the non-transparent criteria used by the regulator to revise offers in the strategic reserve will create uncertainty for companies as regards their expected revenues, in particular if investments are needed.

5.3.5 Conclusions on allocation processes

- In Member States covered by the sector inquiry, all the new schemes that are currently being implemented or planned to be implemented with a reasonable degree of certainty include a competitive price-setting process[109]. This is case for instance in France, Ireland, and Italy. Moreover, Ireland and Italy are moving from an administrative to a competitive allocation process
- A properly designed competitive allocation process minimises the costs of the capacity mechanism, as long as its design ensures competitive pressure and prevents the exercise of market power. This can best be achieved by allowing many different existing and new capacity providers to compete. Besides the allocation process design, eligibility criteria and capacity product features play a crucial role in this respect as they explicitly or implicitly influence the number of capacity providers that can take part in the process (see Sections 5.2 and 5.4 respectively).
- The implementation of a decentralised allocation process in a highly concentrated market with vertically integrated undertakings is more prone to the exercise of market power than a central buyer mechanism as it allows the dominant vertically integrated undertakings to discriminate against their competitors.
- A competitive allocation process is more likely to reveal the real value of capacity and therefore to send adequate signals for market entry and market exit, ,as long as prices are transparently set.

[109] The new Spanish support scheme for plants burning domestic coal should employ an administrative allocation process. However, it is not yet clear whether Spain will implement this mechanism.

5.4 The capacity product: obligations and penalties

5.4.1 Capacity products

Once Member States have selected the capacity providers that could contribute to addressing the identified adequacy problem, they need to design the most suitable 'capacity product' to achieve that aim. In other words, they need to develop the rules determining what exactly capacity providers are required to do in the capacity mechanism in return for receiving capacity remuneration (their 'obligation'), and what happens if they fail to do what they are required to do (usually a 'penalty' of some kind). These obligations and penalties are important to provide an 'incentive effect' on the capacity providers benefitting from capacity remuneration, and ensure that they deliver secure and reliable supplies to consumers.

If Member States fail to design a capacity product to correspond to the specific generation adequacy problem identified, the capacity mechanism will be unable to attain its objective, or it will only be able to attain it at unnecessarily high costs. The latter would for instance be the case where ill-designed capacity products have the effect of unnecessarily restricting participation to the mechanism.

In view of the importance of capacity product design for the appropriateness of capacity mechanisms, this section provides an overview of the obligations and penalties found in the capacity mechanisms included in the inquiry and seeks to identify the impacts that they have.

5.4.2 Findings of the sector inquiry

All of the capacity mechanisms covered by the inquiry include some kind of obligation to ensure the recipients of capacity payments do something to contribute to security of electricity supply. However, these range from a very basic obligation to build and operate a power station, through obligations linked to fulfilling instructions from the TSO (e.g. turn on and generate), to more complex obligations (e.g. reliability options requiring financial paybacks when a strike price is exceeded by a reference price). There is also a wide range of penalties. Some mechanisms simply exclude capacity providers from receiving future payments if they fail to meet their obligations, but most require capacity providers to return the payments earned or even pay an additional penalty on top of this.

5.4.2.1 Obligations

To some extent the design of the capacity product depends on the type of capacity mechanism, but there are various common features of the obligations imposed on capacity providers.

Period of obligation

Some capacity mechanisms require capacity providers to fulfil obligations all year round whenever needed, as in the German network reserve or the British capacity mechanism. Others only require capacity to fulfil obligations during the winter when electricity demand is generally highest. In the Swedish strategic reserve, capacity must be available between 16 November and 15 March each winter. In Italy the TSO defines the 'critical days' during which capacity providers must be available in advance of each delivery year. In France, the obligation is even more limited, since capacity providers are only obliged to make their capacity available in specific hours where demand is highest. These hours can take place in a maximum of 25 days a year, and are announced day ahead by the TSO.

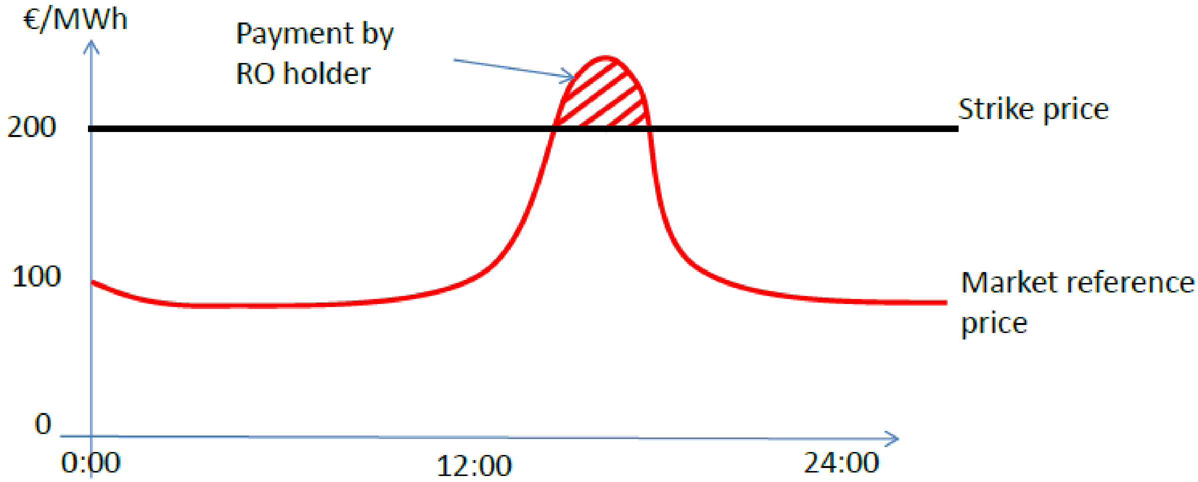
Nature of obligation

In strategic reserves the obligation for participating capacity providers is normally to deliver electricity when instructed by the system operator by generating electricity or reducing demand. And the initial trigger event for the system operator to do this is often the day-ahead market not clearing.

In the proposed French de-central obligation scheme certified capacity providers must ensure they make their capacity available in peak demand hours, and suppliers must ensure their demand in these hours is covered by capacity certificates.

In the schemes proposed for Ireland and Italy, the capacity product is a reliability option. This obliges the capacity provider to pay the difference between a market reference price and a strike price whenever the reference price goes above the strike price.

Figure 31: Overview of reliability option



Source: Commission for Energy Regulation (Ireland) and Utility Regulator (Northern Ireland)

A reliability option does not in itself create a direct obligation for the capacity provider that he has sold the option to do anything particular in the electricity market. However, the potential paybacks under the option mean the capacity provider has a strong incentive to make sure it sells electricity at least at the reference price so that it has revenues to make any required contract paybacks. The extent to which a reliability option product provides incentives for flexibility depends on the reference market chosen for the option contract, and the ability of this market to signal scarcity. The reliability option capacity product also allows consumers to be protected from potential high electricity prices at times of scarcity, since all capacity contracted in a capacity mechanism with a reliability option product will have to payback any excess revenues from the sale of obligated capacity above the reliability option strike price.

In Italy, the reference market is a basket of the day-ahead and ancillary services markets. In addition to the payback requirement of the reliability option, participants will also be obliged to place bids in the day-ahead market for 100% of their contracted capacity. Any contracted capacity not taken in the day-ahead market must then be bid into the ancillary services market. This appears to be designed to enable a reference to the ancillary services market which should provide better signals of scarcity than the day-ahead market, while ensuring the day-ahead market remains liquid.[110]

In the 2003 Irish tender capacity mechanism, selected generators are granted Capacity and Differences Agreements (CADA). These function in a similar way to reliability options, since when the market price is superior to the strike price defined in the CADA the beneficiaries must reimburse the difference between the market reference price and the strike price. In the French tender for new capacity in Brittany, the premium paid to the beneficiary for being available is fixed and revenues generated from the sale of electricity on the market are not taken into account.

Notice period

The definition of a capacity mechanism obligation often features a warning or notice period so that capacity providers have a clear signal to start warming up ready to deliver electricity when they are needed. In strategic reserves (for example in the existing Belgian, Polish and Swedish schemes and the abandoned Danish scheme), participants are obliged to run when instructed to do so by the system operator, but receive a varying notice period. In Poland contracted plants must be able to start generating their full output within 17 hours; in Sweden within 16 hours (while demand response receives 30 minutes' notice); in Denmark within 10 hours; and in Belgium normally within 6.5 hours[111] (while demand response receives 8 hours' notice).

In market wide mechanisms it is not necessary to have a central notice period and in some designs participants are required to react to market forces. This is for instance the case in the planned mechanisms in Ireland and Italy where participants will simply have to repay the difference between the market reference price and the reliability option strike price whenever the reference price exceeds the strike price. This means they have to judge for themselves the risk of high reference prices and be warmed up and ready to deliver when necessary. By contrast, a notice period is included in the French capacity mechanism: the hours during which generators and demand response operators should be available are communicated by the TSO day-ahead.

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[110] Without the obligation to bid day ahead, participants may withhold their capacity until closer to real time to try and ensure they have sold sufficient electricity at the reference price that they can afford to make any required paybacks.
[111] This is the maximum time allowed by the TSO, but justified deviations may be possible.

Limitations on use

A capacity product could simply oblige all remunerated capacity to be provided whenever needed and for as long as needed at any time throughout the period of obligation (e.g. the year or the winter). This is, for instance the case for the Portuguese availability incentive mechanisms. However, many designs include limitations on the number of times a resource can be called, and/or the duration for which a resource may have to provide its capacity continuously. In the Polish strategic reserve for example, the system operator can only require capacity providers to start from cold a maximum of 5 times per week, and resources are only obliged to provide power for a maximum of 8 hours per day. There are also maximum activation durations in the Belgian strategic reserve. In the Italian targeted capacity payment mechanism, capacity providers are required to be available only during 'critical days' defined in advance by the TSO. There are also often different rules specific for demand response (see sub-section 5.4.3.2).

Testing

Most capacity mechanisms include the potential for testing by the system operator to ensure that contracted resources are actually capable of meeting their obligations even in years when there are no periods where obligations apply. This can be performed either as a precondition for participation to the mechanism or while the mechanism is in place, to test that the selected providers remain able to meet their obligations.

The testing of capacities during the capacity mechanism is for instance done in the French de-central obligation scheme, the Spanish interruptibility scheme and the Portuguese availability payments scheme. Demand response providers replying to the sector inquiry also insisted on the barrier to entry that could be created by excessive testing of demand reduction capacity. They argue that the impact of testing the availability of power plants is not comparable to that of testing demand reduction services, since in the latter case effective demand curtailment is required.

New projects

Capacity mechanisms can also include penalties and/or require collateral related to the building of new capacity on time. In the French de-central obligation scheme, for example, new demand response capacity must deposit a bank guarantee in order to be certified. In Brittany, if the beneficiary does not make the plant operational on time, penalties apply. In the planned Irish scheme, a range of physical and financial requirements for bidders intending to develop new capacity are being considered, in view of the risk that they fail to deliver or bid without a firm intention to actually make the capacity available. Possible requirements are the need to demonstrate that the plant can connect to the grid in time, that it has the necessary planning consents, a sound business plan and a sufficient level of creditworthiness.

5.4.2.2 Penalties

Once the capacity obligation has been defined, to ensure capacity providers have incentives to meet their obligations it may also be necessary to design penalties that will apply if the obligation is not fulfilled. These can be implicit penalties – for instance the need to pay back the difference between the strike price and the reference price in mechanisms where the product is a reliability option – or explicit penalties which can be charged in case the obligation is not met.[112]

Generally, in the Member States that apply explicit penalties, it is rare for participants to be able to lose 100% of the remuneration they receive from the various schemes. There are however some exceptions.

In the Spanish 'availability incentive' capacity payments scheme, beneficiaries can lose up to 75% of payments through penalties, and will be ineligible for future years if less than 60% of remunerated capacity was available on average over the previous year. By contrast, in both of the Portuguese capacity payment schemes, plants that are available less than 70% of the time will lose their entire remuneration and providers that consistently fail to meet their obligations can eventually be excluded from the mechanism.

Also in the abandoned Danish strategic reserve capacity providers that consistently failed to meet their obligation could have lost 100% of the remuneration they received from the scheme through penalties. Providers could also have lost more than this since they potentially faced imbalance penalties on top of their capacity mechanism penalties if they did not deliver their contracted strategic reserve when called by the TSO.

In the planned Italian central buyer mechanism, capacity providers face a number of penalties for failure to make bids in the reference markets corresponding to the whole of their contracted capacity. In addition to paying the difference between the reliability option reference price and strike price, they will not receive the capacity payment for the whole month in which they did not fulfil their bidding obligation. Furthermore, in case of a prolonged failure to meet the bidding obligation, capacity providers will have to pay back capacity premiums already received. Additional penalties apply if beneficiaries fail to pay back the difference between the strike price and the reference price. This means that capacity providers could face penalties that are potentially much higher than the total capacity remuneration received.

In almost all of the Member States included in the sector inquiry that apply explicit penalties, these do not appear to be linked to VOLL. The only exception is Italy where

[112] There can even be positive incentives, which allow for an extra payment on top of electricity revenues and the capacity payment.

the value of lost load has been identified to be EUR 3,000 / MWh and the reference price could potentially rise to this level.[113]

Allowable exceptions

Penalties could be applied immediately and for any lack of delivery against the obligation. However, there are usually exceptions to the obligation that reduce risk for capacity providers.

The proposed strategic reserve in Denmark does not impose penalties through the capacity mechanism so long as at least 85% of the capacity called by the system operator is delivered (though imbalance settlement penalties may still apply). Under the Spanish 'availability incentive', capacity providers only need to prove that 90% of the capacity receiving availability payments was available in peak periods.

In Poland, capacity providers in the strategic reserve are allowed up to 1440 hours of planned outages in every two consecutive years, and up to 360 hours of unplanned outages each year before any penalties are due. In the Swedish strategic reserve, generation capacity providers in the strategic reserve must be available for at least 95% of winter hours to avoid penalties. Similarly in Brittany the new plant needs to be available for 95% of the time, whereas in the abandoned Belgian tender a 80% availability during winter was required. In the abandoned Danish strategic reserve, capacity providers had to be available for 90 % of overall hours in a year.

Note in many schemes aspects of obligation design already effectively build in exceptions before penalties apply – for example the notice period and limitations on use (see section 5.4.2.1 above).

5.4.2.3 Reform of capacity products in the United States

The capacity mechanisms in PJM and ISO New England, which each include a market wide central buyer capacity mechanism, have both had the design of their obligations and penalties overhauled recently in response to lessons learned during the 2013-2014 'polar vortex'.

During the polar vortex a large proportion of contracted capacity was not actually able to deliver when it was needed because of a lack of firm fuel supplies or failures to operate due to the cold weather. It was found that in some cases contracted resources preferred to pay non-performance penalties than expensive fuel supplies.[114] Since these events, the capacity products in both ISO-NE and PJM have been reformed so that there are much stronger signals for delivery ("pay for performance") of contracted capacity when it is needed.

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[113] Note in reliability option schemes the penalty would be linked to VOLL if the introduction of the capacity mechanism was accompanied by market reforms allowing the reference price to rise to VOLL.
[114] See: http://www.ausenergy.com/2014/02/the-illusion-of-reliability-ne-isos-capacity-market/

5.4.3 Issues identified

5.4.3.1 *There is a trade-off between security of supply and the period of a capacity obligation*

A more limited period of obligation reduces the risk for the participants in the capacity mechanism. A particularly time-limited obligation like that chosen in France and Italy can also increase participation, particularly by demand response providers which may struggle to provide capacity over longer durations. If it reduces risk for participants and increases participation, a more limited obligation may therefore appear more cost-efficient. However, this comes at the cost of more limited insurance for security of supply.[115]

Nevertheless, where the problem the capacity mechanism is targeting is clearly seasonal or linked to a problem that only occurs in specific hours, a shorter obligation period may be appropriate. A more limited obligation period should also reduce the need for any exemptions related to the obligation, for example due to maintenance, since beneficiaries should be able to schedule planned maintenance outside the obligation period.

Also the caps on the limitations on the use of the contracted capacity may reduce the overall level of security provided by a capacity mechanism. However, these negative effects must be balanced out against the positive effects of risk and cost reduction for capacity providers, and potential increased participation to the mechanism (and therefore less costs overall as a result of increased competition).

5.4.3.2 *Specific products for demand response*

Demand response is often treated differently to generation within the various mechanisms included in the sector inquiry, for example because it is not always possible for demand response to bid in the market in the same way as a generator, and because of the need to establish a consumption baseline from which to measure the amount of energy delivered by demand response capacity.

There are also often limitations on the obligations for demand response, for example a more limited number of required consecutive hours of capacity delivery. These differences may be justified since they help support the development of demand response and should allow it to play an increasingly significant role in the electricity markets of the future, but such different treatment needs to be carefully considered to avoid any unjustifiable discrimination.

The sector inquiry has furthermore revealed that certain types of capacity mechanism may face very specific challenges to optimise full demand response participation, by reason of their set-up. As such, the supplier obligation developed in France required

[115] More limited capacity mechanism obligations may also for example mean that more balancing services or additional measures are needed alongside the capacity mechanism.

specific design solutions to accommodate two different types of demand response participation: implicit and explicit participation. The former refers to the reduction of the supplier obligation through "management" of – mostly residential and SME – demand by electricity suppliers, whereas the latter refers to the direct participation of large industrial users and demand response aggregators to the mechanism, often through the certification of their capacity. Since the French authorities specifically wanted to encourage also implicit demand response participation, the availability obligation for both types of demand response differed.

5.4.3.3 Capacity products risk distorting electricity prices

Capacity mechanisms usually have a close link with electricity prices, since electricity prices rise to provide a signal that there is scarcity in the market.

Once capacity mechanisms are introduced they will – in most cases – reduce the extent to which local electricity prices remunerate capacity. Capacity will be fully or partially rewarded separately through capacity remuneration. If a capacity product includes an obligation that: i) pays or penalises capacity providers on the basis of capacity delivered (payments/penalties per MWh); or ii) that introduces a price cap in the market, then there is a greater risk of distortions to market functioning.

Implicit market price caps could for example potentially be set by a reliability option strike price that leaves no incentives for bidding above that level. However, any capacity able to bid exceed its capacity mechanism obligations in a particular period – for example by generating more than the de-rated capacity for which it sold reliability options – would still be able to set higher prices than the strike price.

Box 3: The 'slippery slope' effect

A strategic reserve that is dispatched before possibilities for the market to match supply and demand have been fully tested can also act as a cap on market prices. This risk can be avoided by dispatching the reserve only when the market has failed to clear despite prices reaching an appropriate wholesale market price cap. This should still enable capacity providers outside the reserve to receive scarcity prices and therefore enable peaking plants to earn their fixed costs. If the reserve is dispatched more frequently or if in times when the reserve is dispatched the market price is not set to the cap, then the reserve will have created additional missing money by reducing the possibility of high market prices.

Where missing money remains in the electricity market and is only corrected for beneficiaries of the reserve, there is the potential for a strategic reserve to become bigger and bigger as more plants close or threaten to close unless they are included in the strategic reserve (sometimes called the slippery slope effect). This effect seems to have occurred in Belgium where for winter 2014-2015 the government initially mandated the TSO to contract 800 MW of strategic reserve, which was already four months later increased to 1,200 MW[116], while for winter 2015-2016 the government mandated the TSO to contract a reserve totalling 3,500 MW (i.e. 23.8% of total operational installed capacity in Belgium in 2014)[117]. Also the German Network Reserve increased from an initial 1.4 GW in 2012/2013 to 4.8 GW for the winter of 2015/2016.

In Sweden, the reserve has actually become smaller over time – shrinking from 2 GW to 1 GW. However, it has no so far proved to be a transitional intervention. The reserve was introduced in 2003 and is still in place in spite of plans to phase it out. In 2015, the public authorities have announced to extend its duration once more from 2020 to 2025.

Where capacity penalties provide an incentive for the delivery of required electricity when needed, these penalty signals may be considered to replace the signals the electricity market would otherwise need to provide for delivery of electricity at the right times. However, if a capacity mechanism acts as a replacement for high electricity prices at times of scarcity, there will not be an efficient signal for imports to the Member State having implemented that capacity mechanism at times of need. Nor will there be an efficient incentive for demand response participation in the electricity market outside the capacity mechanism.

The risk of distortions can be reduced by ensuring that the electricity market continues to function effectively – including by sending the right signals for short term dispatch (and to a large extent therefore also for investment in flexibility) – regardless of the

[116] A total of 850 MW, consisting of 750 MW of generation reserves and 100 MW of demand response reserves, was finally contracted.

[117] In reality only 1535.5 MW, consisting of 1177.1 MW of generation reserves and 358.4 MW of demand response reserves, could be contracted.

introduction of a capacity mechanism. As underlined in Chapter 2, it is important to realize the necessary reforms to the electricity market that enable these short term signals.

The capacity product too will need to be designed carefully to avoid taking too much of the scarcity signal out of the electricity price (and yet also to ensure an incentive effect on capacity providers).

5.4.4 Conclusions

- Some capacity products – such as reliability options – protect against the potential for a capacity provider to be overcompensated from a combination of capacity payments and electricity market revenues – which may be uncertain, particularly where commitment periods are long (see sub-section 5.4.2). This protection could help enable a capacity mechanism to limit opportunities for the abuse of market power, particularly in a system where electricity prices can rise at times of scarcity.

- In the mechanisms that include demand response there are usually different obligations for demand response than for generation. Some differentiation in obligations and penalties between generation and demand response is justifiable in the short term to enable the development of demand response.

- Obligations requiring the verifiable availability or delivery of capacity resources in (potential) scarcity situations are necessary to encourage investment in sufficiently flexible and reliable capacity.

- Unless these obligations are backed by penalties in which it is possible to lose at least as much as you gain from the capacity mechanisms, there may be an insufficient incentive. Testing may also be required if the use of the capacity mechanism is expected to be limited to very occasional situations.

- The design of the capacity product should ensure the majority of signals for flexibility remain in the (increasingly reformed) electricity market, so that the electricity market provides efficient signals for electricity imports and demand response even once a capacity mechanism has been introduced.

6. ASSESSMENT OF THE VARIOUS TYPES OF CAPACITY MECHANISMS

Drawing upon the arguments presented and discussed throughout this Interim Report, this final chapter considers, within the framework of State aid assessment, how each of the types of capacity mechanism identified in Chapter 3 may be able to address well-defined generation adequacy problems.

The designs of the mechanisms vary widely, but all provide financial support for capacity providers and thus they may fall within the category of state aid measures. They can therefore be subject to the Union's rules on state aid and their compatibility with these rules may have to be assessed by the Commission. State aid principles provide an appropriate framework to assess the need for capacity mechanisms to be implemented, their ability to address potential generation capacity shortages, as well as their likely unintended market distortions.

First, in assessing the potential compatibility of public measures it is necessary to clearly identify the objective to be pursued. As explained in Chapter 3, capacity mechanisms by definition have the general objective of contributing to security of electricity supply. However, as reasoned in Chapter 4, Member States should improve their assessments of generation adequacy problems as a basis for the design of a planned capacity mechanism.

After Member States have clearly identified their adequacy problem, state aid rules provide a framework for assessing the possible positive and negative effects of the public intervention. Public support should be designed in the most appropriate way to tackle the adequacy problem. Chapter 5 has presented a number of choices regarding the design of capacity mechanisms. The choices about the design of public measures have to provide incentives to recipients to act in the direction required by the identified objective and also to make sure that the expenditure is proportional, i.e. does not exceed the minimum necessary required by the objective. Moreover, as any public intervention in the market has the potential to distort free competition, Member States should design their support for generation adequacy in such a way as to minimize potential distortions to competition and trade in electricity markets.

The remainder of this Chapter is structured as follows. Section 6.1 recaps the actions needed to establish the necessity for a capacity mechanism. Section 6.2 discusses each type of capacity mechanism in turn, considering their appropriateness to address particular generation adequacy concerns and the possible market impacts arising from their implementation. This high-level assessment draws upon best and worst practices identified in the sector inquiry.

The assessment in this chapter is presented in the form of tentative conclusions for consultation. The assessment and tentative conclusions presented here do not prejudge in any way the outcome of, or replace the need for, a detailed assessment of the compatibility of any individual State aid measure.

6.1 Necessity for intervention through a capacity mechanism

As explained in Chapter 2, a number of market and regulatory reforms have been proposed and are being implemented to varying degrees in some Member States to address concerns about electricity generation adequacy and security of supply. Well-functioning markets have the potential to reduce the need for intervention in the form of capacity mechanisms. Nonetheless, Member States may still consider it necessary to implement capacity mechanisms. As discussed in Chapter 4, the necessity of intervention should be established by determining the necessary generation capacity that cannot be expected to be provided by the market, even after alternative measures have been considered.

Establishing the necessity for state intervention is an essential step in the assessment of compatibility of any capacity mechanism. An accurate generation adequacy assessment will identify in detail the particular circumstances of each electricity market and the need for additional capacity, including the amount and type of capacity required, the timing of any capacity problems and any particular locational capacity needs. For example, a Member State may face a general capacity shortage, i.e. a systemic problem of insufficient investment in new capacity possibly resulting from various factors undermining price signals, risk aversion of investors, coordination failures or the public good nature of reliability. Other Member States may have a local capacity shortage due to network constraints (cross-border or national) that cannot be addressed in due time through alternative means, for example by establishing appropriate bidding zones or investments in transmission infrastructure. Capacity mechanisms may also be designed to solve an urgent and immediate capacity shortage to buy time to reform electricity markets or develop a more permanent intervention to ensure security of supply. There can also be circumstances where there is a specific need for capacity with particular characteristics – for instance flexibility, to ensure a rapid increase of supply in periods of peak demand.

6.2 Appropriateness and market impacts for each type of mechanism

The various capacity mechanisms identified in Chapter 3 can be more appropriate in some circumstances than in others. This may be due to either the ability of a particular capacity mechanism type to deal with certain types of capacity shortage or to other market impacts particular types may have. In each specific case, the appropriateness of a capacity mechanism to address a well-defined need for additional capacity and its likely market impacts will have to be assessed.

This section presents some tentative conclusions on the ability of each type of capacity mechanism to address potential capacity shortages depending on the problem identified, including it is expected to be temporary or more permanent, and location-specific or more general. It also discusses a number of likely market impacts of capacity mechanisms, especially potential crowding-out effects[118] on investment and impact on market structure.

6.2.1 Tenders for new capacity

As described in section 3.1.1, in a tender for new capacity the beneficiary typically receives financing for the construction of a power plant that would bring forward the required top-up capacity.

Tenders for new capacity have been used in Belgium, France and Ireland. In Belgium, the tender was intended to bring on new investment in gas-fired capacity. In France, the tender is intended to bring forward investment specifically in a new CCGT plant in Brittany, where there is the risk of insufficient local capacity and insufficient network connections with the rest of France. In contrast, the tender launched in Ireland in 2003 was open to all types of thermal generation capacity. The Irish tender can be seen as designed to address a temporary need while a more long-term intervention was developed, namely the market wide capacity payment mechanism (see Section 6.2.4 below) which was introduced in 2007.

6.2.1.1 Ability to address capacity shortages

While a tender can ensure new generation capacity is built, the security of supply benefits it delivers may be off-set by the impacts the tender has on existing capacity in the market, and on the incentives for future investment not supported by a tender.

A tender can attract investment in a particular location. However, as explained in sub-section 5.2.3.5, a tender does not correct the underlying issues preventing investment in that region. In the longer term, appropriate incentives for local investment may need to come from the electricity market, i.e. through higher local electricity prices in deficit regions.

A tender for new capacity typically has the advantage of providing for a relatively quick solution to add new capacity, especially when envisaged market reforms that could alleviate the problem are known to take time to implement. In particular, although time will always be needed to construct a new power station, a tender is likely to take less time to develop and implement than a more complex market-wide capacity mechanism. As seen in sub-section 5.4.2.1 (under "New projects"), to ensure timely delivery of the capacity some tenders include penalties for late delivery within the beneficiary's control'. Despite the potential for quick implementation, the long contracts required to bring forward new investment (see sub-section 5.2.2.4) and in some cases the characteristics of the particular technology benefitting from a tender mean that this mechanism is likely to impact the market for many years.

[118] The crowding out effect refers to the potential for publically-supported investments to reduce the potential for independent / private investments that might otherwise have come forward.

6.2.1.2 Possible competition distortions and impact on market structure

Tenders for new capacity may produce a crowding-out effect, as it can be the case also with targeted capacity mechanisms and strategic reserves. As explained in sub-section 5.2.3.4, the appearance of new subsidised generation capacity in the market is likely to be detrimental to the profitability of non-subsidised generation capacity, by depressing electricity prices that remunerate all capacity providers. As a consequence, some existing plants may close sooner than they would otherwise have or some investments that would otherwise have taken place may be missed. This crowding-out effect can undermine the efficacy of tenders for new capacity, if on the one hand they incentivise investment by its beneficiaries, but on the other hand they disincentivise investment by other capacity providers.

A tender may also incentivise opportunistic behaviour of potential investors. Once the national authorities show that they are prepared to subsidise new investment, investors may prefer to wait for a future tender rather than invest on the basis of less certain market returns. As a result, tenders may either put of new investment that would otherwise have come forward, or support the financing of investments that might have taken place anyway, undermining the incentive effect of the measure.

As tender procedures typically offer long-term contracts they provide for relatively great investment certainty and give stronger incentives to market entrants. By lowering barriers to entry, they may therefore limit the market power of incumbents and increase competition. In the Belgian tender, the authorities sought to incentivise new entry by applying a 10% award criterion to take account of the bidder's contribution to competitive market functioning in Belgium. In Brittany, the tender was awarded to a market entrant. In Ireland, the incumbent was not allowed to participate in the tender procedure and the capacity product was designed to limit the possibility of the tender beneficiaries exercising market power for the duration of their tender contract – see sub-section 5.4.2.1. However, although new entry can increase competition in the electricity market, a tender does not provide an enduring response to the potential to exercise market power by participants in that market.

Although they are usually domestic, tenders typically have cross-border impacts. They will increase domestic capacity and therefore reduce opportunities for imports. At the same time, they may slow down plans to improve connection with other geographic areas.

6.2.1.3 Conclusions on tenders for new capacity

A tender for new capacity may be an appropriate temporary measure to incentivise investment (including potentially in a specific location) and offer a route to market for new entrants. A tender can be implemented relatively quickly – subject to the long (eg. 3-4 year) lead time for realising new generation investments and the need to make legacy contract payments for ten or more years where new contracts were required to bring forward new capacity. However, a tender does not effectively address longer term generation adequacy problems, and may exacerbate underlying market and regulatory failures unless complementary reforms are also made.

6.2.2 Strategic reserves

As described in section 3.1.1, in a strategic reserve mechanism the top up capacity needed on top of what the market is expected to provide is contracted and then held in reserve outside the market. Capacity in strategic reserves generally does not participate in the market and is dispatched only in case the market does not clear, i.e. when there is a danger that demand will outweigh supply.

Examples of strategic reserves (excluding interruptibility schemes) exist in five of the Member States included in the sector inquiry: Belgium, Denmark, Germany, Poland and Sweden. All of the reserves are designed to keep existing power plants operational, so that they can be deployed when needed. Only Germany plans to include new generation capacity in its revised network reserve. Only the German network reserve is dispatched more regularly, namely in times where internal grid congestion does not allow for the transmission from generation centres to demand centres.

6.2.2.1 Ability to address capacity shortages

While strategic reserves ensure that back-up capacity is available, the security of supply benefits they deliver may be off-set by their impacts on capacity that remains in the market.

Strategic reserves can be designed to maintain capacity in specific geographic areas where a potential shortage has been identified. As described in more detail in sub-section 5.2.2.5, some strategic reserves contracted capacity located in specific regions within the respective Member States. As with other targeted capacity mechanisms, this enables the strategic reserves to target a local generation adequacy problem without the need for a mechanism to remunerate capacity elsewhere in the market. However, as with a tender, a strategic reserve cannot address the underlying issues that originally prevented local investment and appropriate incentives may need to be provided by electricity prices (see sub-section 5.2.3.5 of this report).

From a timing perspective, strategic reserves can be seen as transitional measures in the sense that they may delay the closure of some generation capacity. Hence, if there is a credible reason why there is a transitional generation adequacy problem – for example because sufficient new merchant investments are underway but not yet complete, or longer term reforms require time to implement – a reserve could be appropriate as it offers an immediate option to prevent existing plants from shutting down. In view of the objective of strategic reserves, generally there is no need for very long contracts (see sub-section 5.2.2.4).

6.2.2.2 Possible competition distortions and impact on market structure

Strategic reserves are typically called to supply electricity when market prices increase above a certain threshold. Consequently, they tend to limit the ability of electricity prices to increase in moments of scarcity and risk reducing incentives to invest in capacity which might, in turn, aggravate the initial capacity shortage. Hence, similarly to tenders for new capacity and targeted capacity mechanisms, they may induce a crowding-out effect on investment, reducing their ability to address a potential capacity shortage. As explained in sub-section 5.4.3.3, this concern could be minimised through a design that ensures the reserve is only dispatched when the market fails to clear and setting market prices, in these instances, to an appropriately high price cap. Even if the reserve is only dispatched when the market fails to clear, investors have expressed the credible concern that the reserve represents an additional regulatory risk because the national authorities may be tempted to change the rules and dispatch the reserve more often, for example in response to a prolonged period of high electricity prices. Such a design is also required to ensure that strategic reserves do not distort cross border markets.[119]

In addition to the crowding-out effect, a strategic reserve may affect market structure if it creates incentives for plants to announce closures that would not otherwise have taken place, because the expected profitability for a certain plant is higher within the strategic reserve scheme than outside the scheme. As a result, the strategic reserve can in this case accelerate exit from the market. Belgium provides a good example of how a strategic reserve can trigger this effect. Many troubled generators announced their closure (legal precondition to enter the reserve) in order to be able to enter the reserve so that the demand for the reserve increased substantially from the first to the second year after its introduction (the 'slippery slope' effect described in Box 3 in sub-section 5.4.3.3). This reduced the scope of the competitive market. Moreover, in particular gas-fired power plants (which in Belgium the main production segment where the smaller competitors to the incumbent are active) risk being drawn into the growing reserve.

Another source of concern arises from the potential ability and incentive of an incumbent with presence in the strategic reserve to withhold capacity in the market to trigger a price increase and the activation of the strategic reserve, provided that its profits from activating the reserve outweigh the cost of withholding capacity. Finally, an additional source of concern can relate to the exercise of market power may arise when the candidates to be integrated into a strategic reserve are very few. In this case, it can be that the tender for the reserve is not sufficiently competitive, which would reduce the ability of a strategic reserve to cost effectively address a transitional generation adequacy problem.

6.2.2.3 Conclusions on strategic reserves

Strategic reserves may be appropriate transitional measures in situations where for example the completion of new capacity or transmission infrastructure or the

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[119] It should be noted in this context that it is the Commission’s intention to develop, in the context of the market design initiative, a regional framework for the effective sharing of resources also in situations when markets may not deliver solutions (e.g. in emergency situations affecting various neighbouring countries).

implementation of market improvements are underway and expected to address underlying generation adequacy concerns. However, the reserve alone does not address underlying market or regulatory failures, and may exacerbate the problems preventing sufficient capacity investments in the market outside the reserve.

As a strategic reserve is unlikely to trigger investment in new generation capacity it does not appear to be suitable in a market requiring such investment.

6.2.3 Interruptibility schemes

As explained in subsection 3.2.3, beneficiaries of interruptibility schemes are typically paid a fixed price for the demand response that they commit to make available when needed, as well as a price for demand reductions actually delivered.

The sector inquiry found interruptibility schemes in six of the Member States covered by the inquiry: Germany, Italy, Ireland, Poland, Portugal, and Spain. Interruptibility schemes are a particular type of strategic reserve which only includes demand response capacity.

6.2.3.1 Ability to address capacity shortages

There are various reasons why governments or TSOs develop interruptibility schemes. Where used to procure demand response capacity to cover a general capacity shortage – as opposed to ancillary services to manage short term frequency deviations – interruptibility schemes can reduce incentives to invest in flexible generation capacity, in the same way as strategic reserves do. Whether interruptibility schemes actually have this effect depends to a large extent on their design.

Most of the interruptibility schemes currently in place are used by the TSO as an ancillary service, i.e. as an instrument the TSO uses after gate closure, remotely and without any prior notice to the providers of the service. In such cases, the impact of the schemes on market incentives is limited. Moreover, the fact that more demand response potential may be activated thanks to the specific support of the scheme may offset part of the need for additional flexible generation capacity as underlined in sub-section 2.3.1.

Re-dispatch services can be provided by other, competing sources of flexibility so they do not necessarily have to be provided solely by demand response. A scheme limited to demand response excludes other providers of flexibility and therefore Public authorities choosing to introduce DSR-specific measures should ensure they can justify any limited eligibility criteria. One justification for separate interruptibility schemes for re-dispatch purposes may be their potential to unlock new capacities and create flexibility that would otherwise not have been at the TSO's disposal.

Regarding their geographic scope, whilst interruptibility schemes generally apply country-wide, their use can be local if the TSO sees a purely local need for shedding loads, for instance in response to network constraints. This is the case for the German interruptible load scheme which, as underlined in sub-section 3.2.3 can be used by the TSOs to compensate for congestions between the North and the South.

From a timing perspective, the implementation of interruptibility schemes does not in principle require long-term investments or commitments and therefore can be seen as an appropriate measure if the problem is of transitional nature. For instance, the relatively short contract times applied in interruptibility schemes (see sub-section 5.2.2.4) have the advantage of allowing for amending demand quickly. However, there is no evidence from the sector inquiry that interruptibility schemes are used mainly or solely as transitional mechanisms.

6.2.3.2 Possible competition distortions and impact on market structure

Most of the interruptibility schemes currently in place are relatively small in size and where this is the case their impact on electricity market functioning is unlikely to be significant. Moreover, as underlined in Chapter 2, there is a growing need for a flexible demand side and interruptibility schemes can be appropriate to kick-start the development of demand response that will in future be able to compete with other sources of flexibility on the wholesale or the balancing market. The effects of interruptibility schemes need to be monitored closely however as they have the potential to distort industrial markets if the selection criteria (and in particular minimum size requirements: see sub-section 5.2.2.2) are unnecessarily restrictive. Where schemes are devised by the government rather than independently by the TSO it will be particularly important to ensure that they truly serve the purpose of providing a service that is needed by the TSO at proportionate cost and without disproportionately affecting competition with other sources of flexibility. When this is not the case, these schemes risks becoming – as put forward by various respondents to the sector inquiry – aid to the industrial energy users frequently selected to provide the contracted demand response.

6.2.3.3 Conclusions on interruptibility schemes

Whilst the benefits of unlocking additional demand response potential are apparent, the design of interruptibility is essential to ensuring that such schemes truly provide added value to the TSO in ensuring system security in a cost-efficient way. Interruptibility schemes do not appear to provide an enduring solution to a capacity shortage problem, but in the short term may be appropriate to help develop demand response. In the longer term, there may be an enduring need for particular ancillary services procured by TSOs from demand response, but in order to reduce the risk of over-compensating the providers of such services, requirements should be specified and beneficiaries selected through competitions open to all potential providers.

6.2.4 Capacity payments (targeted and market-wide)

As explained in sub-sections 3.1.1 and 3.1.2, in these models a central body sets the price of capacity. In market-wide capacity payments the centrally set price is paid to all capacity expected to be needed to meet demand in the market. In targeted capacity payments the centrally set price is paid to a subset of capacity operating in the market, for example only to a particular technology, or only to capacity providers that meet specific criteria.

The sector inquiry found targeted capacity payment schemes in Italy, Poland, Portugal, and Spain and one market-wide capacity payment scheme in Ireland (see sub-sections 3.2.4 and 3.2.7).

6.2.4.1 Ability to address capacity shortages

Targeted capacity payments may keep the existing plants benefitting from the payment from closing, or support investment in eligible beneficiaries, but as with the tender and reserve models, they risk worsening the situation for those that are not eligible.

Market-wide capacity payments are designed to provide incentives to all market participants and therefore may be perceived as suitable when capacity shortages are not specific to a certain type of generation or to certain geographic areas. In contrast, targeted capacity payments can be designed to more specific needs, making payments accessible only to generators of certain types or in certain locations.

None of the targeted capacity payments mechanisms identified in this inquiry pay only for capacity in a particular geographic region. Moreover, alternative measures may often be available to address local shortages more efficiently than targeted capacity payments, like creating locational electricity prices which provide longer term incentives not only for local capacity investment but also investment in cross-zonal transmission, or through market coupling the right signals for the use of existing transmission infrastructure.

In both market-wide and targeted capacity payments, the major challenge for the efficient design of a capacity payment scheme is the identification of the correct level for the capacity payments without a competitive process. As explained in detail in section 5.3, it is difficult to obtain through an administrative process a level of remuneration that incentivises the right amount of additional generation capacity. Setting the wrong level of payments leads to either under- or over-investment in capacity, compared to the level desired. This greatly compromises the ability of capacity payments to efficiently meet its objectives.

In Spain, the existence of several targeted schemes suggests that no individual targeted capacity payments mechanism has been considered sufficient to ensure generation adequacy (see sub section 5.2.3.8). Portugal also has two capacity payments schemes, as well as a separate interruptibility scheme. Since introducing a market wide capacity payment scheme in 2007, Ireland does not appear to have needed additional interventions to ensure generation adequacy.

6.2.4.2 Possible competition distortions and impact on market structure

As with tenders and strategic reserves, targeted capacity mechanisms may produce a crowding-out effect. The appearance or maintenance of subsidised generation capacity in the market is likely to be detrimental to the profitability of non-subsidised generation capacity, by depressing electricity prices that remunerate all capacity providers. This crowding-out effect can undermine the efficacy of capacity payments if it deters investment by ineligible capacity providers.

Moreover targeted capacity payments can distort technology choices of investors. They support specific types of generation capacity as defined centrally by the authorities, to the detriment of alternative choices that market players could have made in response to market signals.

More generally, some investors have raised the concern that since there is no competitive process in which new projects might come forward and take market share from existing capacity providers, both targeted and market wide capacity payments may contribute to keep in the market capacity that would otherwise exit and therefore constitute a barrier to new investment in generation. They may therefore preserve the existing market structure and generation mix.

It is in principle conceivable that targeted capacity payments could be paid only to new entrants or smaller generators, but there are no examples of such a practice and it would be difficult to justify on objective grounds. In Greece, for example, the flexibility mechanism intends to support the gas-fired power plants of the independent power producers as well as of the incumbent because both operate plants fulfilling the technical criteria to ensure the necessary flexibility.

There can be concerns that capacity payments reinforce the market position of incumbents precisely by constituting an additional barrier to the entry of new participants in the generation of electricity. To counter market power concerns, for instance, the Irish capacity payment mechanism requires market participants to bid at the level of their short run marginal costs into the electricity market. However, this accompanying market rule risks causing the capacity mechanism to become a permanent feature of the market (unless other reforms are made) and risks undermining the efficiency of electricity prices as a signal for imports at the right times.

6.2.4.3 Conclusions on capacity payments

Targeted capacity payments suffer from many of the drawbacks of the tender and strategic reserve models, with the additional drawback that there is no competitive price setting process which increases the risk of inefficiency and makes the level of remuneration difficult to justify. Market wide capacity payments could in theory be designed to address long term regulatory or market failures, but such schemes do not competitively reveal the value of capacity. Capacity payment schemes (both targeted and market-wide) are therefore likely to be the least efficient models of capacity mechanism.

6.2.5 Central buyer mechanisms

As described in sub-section 3.1.2, in a central buyer mechanism the total amount of required capacity is set centrally, and then procured by a central buyer through a process in which potential capacity providers compete. This competitive bidding determines the price paid to capacity providers.

Sub-section 3.2.5 explains that examples of central buyer schemes were found in two of the Member States included in the sector inquiry: Ireland and Italy. Both mechanisms are still in development and are not yet operational. Examples of central buyer schemes are also found in the British capacity mechanism, and in the United States including in the ISO New England and PJM systems on the East Coast.

These mechanisms are being introduced by Ireland and Italy because of concerns that there are systemic electricity market failures that cannot be addressed – at least in the medium term – only through reforms to the energy only market. The UK presented similar reasons for the introduction of the British mechanism.

6.2.5.1 Ability to address capacity shortages

A central buyer mechanism produces a competitive price through an auction for the total required capacity, as established by the central buyer. This ensures that the desired amount of generation capacity is actually procured and, provided the auction is competitive, ensures the cost of procuring such amount of generation capacity is minimised. A central buyer mechanism can therefore efficiently attain the desired level of generation capacity, if appropriately designed.

A number of design features can contribute to the competitiveness of the procurement procedure and the efficiency of the outcome. Eligibility rules that broaden the set of potential participants in the mechanism, for example, are likely to contribute to this competitiveness (as explained in Section 5.2).

An important aspect in central buyer mechanisms – as in other volume-based mechanisms – is the need for a central body to estimate the required amount and type of generation capacity to attain the desired level of system reliability. While this may minimise risks of insufficient provision of generation capacity, it risks leading to excess capacity if risk-averse central authorities set the targets for generation capacity at unnecessary high levels. This risk exists to some extent in every capacity mechanism type, however, and should be mitigated by links to a thorough and transparent adequacy assessment, and appropriate oversight of regulators or independent experts to verify the parameters set by governments and TSOs.

Regarding the geographic scope of the intervention, with eligibility criteria open to all potential capacity providers, a central buyer mechanism is able to address a systemic missing money problem. Central buyer mechanisms can also be used to address local shortages. For instance, to encourage sufficient investment in different locations the central buyer mechanisms in ISO New England and PJM, and the proposed mechanism in Italy, the auctions discover zonal capacity prices in different geographical areas covered by the mechanisms, efficient rules for cross-zonal participation are needed in such a design to ensure appropriate incentives for investment in additional transmission as well as generation and demand response capacity.

Regarding timing in the implementation of central buyer mechanisms, the long lead time between the auction and obligation period required to enable new projects to be built, and the potential for longer contracts for new capacity, limit the ability to quickly move from a central buyer model to an alternative market design. These mechanisms may therefore be less appropriate as very short term transitional interventions than tenders or strategic reserves. However, the mechanism can correct itself because when more capacity is available and/or investors expect future electricity revenues to fully compensate their investments, the price of the mechanism will drop, in theory to zero when there is no longer any missing money.

6.2.5.2 Possible competition distortions and impact on market structure

So long as it is possible in practice for new projects to compete with the least efficient existing capacity providers, a central buyer model can attract new entrants. The possibility of competition from new entrants should also help ensure that the market power of participants in the capacity auction itself is limited.

To assess the impact of this model on the market structure, the existence of longer contract lengths for new investments is a key parameter (as discussed in sub-section 5.2.2.4). Unlike the de-central obligation model, the central buyer model can be designed more easily to accommodate multiple contract lengths. This may facilitate the participation of new projects needing to commit upfront to high initial investment costs, but needs to be balanced against the potential discrimination between different capacity providers due to different contract lengths.

The possibility of effective participation from new entrants in this type of mechanism means that it can be designed in such a way that no barriers to entry are added in electricity generation. The competitive threat from potential entrants can be an effective constraint to incumbents with strong market positions, and the eventual participation of foreign capacity would constitute an additional competitive constraint[120]. Moreover, the capacity product in a central buyer model can also be designed to limit market power in the *electricity* market. For example, the reliability options being developed in Ireland and Italy should still allow high prices to be set in the electricity market (which in turn will send efficient signals for imports and demand response) while also limiting the extent to which capacity providers that have benefitted from the capacity mechanism can access these high prices at consumers' expense.

6.2.5.3 Conclusions on central buyer mechanisms

A central buyer mechanism has the potential to solve a general shortage of capacity efficiently, but its success depends greatly on appropriate eligibility criteria and a design of the capacity product that ensures achieving a well-defined objective with minimal distortions to the functioning of the electricity market. It may be particularly useful

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[120] Although a solution appears possible that would allow cross-border participation in central buyer and de-central obligation capacity mechanisms (see Annex 2) until this is enabled there will be long term distortions to locational investment signals, with stronger incentives for investment in capacity mechanism areas than in neighbouring areas without capacity mechanisms or in new transmission linking the two (see sub-section 5.2.3.7).

where concerns about potential market power prevent a more decentralised approach and/or longer contracts are required to bring forward new entry.

Some inefficiency may be unavoidable in any central buyer design, for example due to the complexity of carefully assessing all the design features, the dependence on central judgements by risk averse decision makers – though this can be reduced by including a role for the regulator or independent experts in the process – and the need to centrally determine the required flexibility characteristics of capacity providers through the design of the capacity product.

6.2.6 De-central obligation

As explained in sub-section 3.1.2, in a de-central obligation mechanism an obligation is placed on electricity suppliers / retailers to contract with capacity providers to secure the total capacity they need to meet their consumers' demand. The difference compared to the central buyer model is that there is no central bidding process, but market forces should still establish the price for the required capacity volume.

As explained in sub-section 3.2.6, the only de-central obligation mechanism found in the sector inquiry is the capacity certificates market being introduced in France.

6.2.6.1 Ability to address capacity shortages

Like the central buyer model, a supplier obligation is in principle suitable to address a systemic, market-wide missing money problem, subject to appropriate eligibility criteria and a suitable capacity product.

It is less likely to be appropriate when there added generation capacity required is of a certain type or in a certain geographic location. While in principle it could be conceivable to enable locational investment signals in a de-central obligation mechanism, for example by obliging suppliers to purchase a proportion of their capacity certificates from providers located in a particular geographical location, this would result in significant added complexity and there are so far no precedents of such type of mechanism.

From a timing perspective, the complexity of designing and implementing de-central obligation mechanisms seems to suggest they are unlikely to be seen as a transitional intervention. However, compared to the central buyer mechanism the absence of long contracts may reduce the future costs of exit from the mechanism. In a well-designed and competitive de-central obligation mechanism, once the required level of generation capacity is attained, capacity prices should theoretically fall to zero in the same way as in the central buyer mechanism.

Contrary to the central buyer mechanism, a de-central obligation does not require a central determination of the generation capacity required to ensure the targeted level of system reliability. In a de-central obligation mechanism the central authority establishes only the coverage rate of expected demand that market participants need to attain through bilateral contracting, leaving the estimation of expected demand to each supplier.

This does not mean that the risk of over or under-procurement is absent. It can materialize for instance if the design of penalties that apply for insufficient procurement allow suppliers to strategically underestimate their expected demand to reduce procurement costs, or are so high that suppliers overinsure themselves by purchasing extra capacity. There may also be other administrative elements that influence the overall level of security that will be achieved by such a mechanism.[121] Other causes for over or under procurement are not specific to de-central obligation mechanisms, like a genuine over or underestimation of medium to long term capacity needs or the lack of visibility of suppliers about their future customers' demand, which can also occur when the required generation capacity is determined centrally.

6.2.6.2 Possible competition distortions and impact on market structure

While de-central obligation mechanisms are open to the participation of new entrants, their effective participation depends on the possibility and appetite of market players for engaging in longer duration capacity contracts, which in turn is influenced by capacity price uncertainties. Almost two-thirds of market participants responding on the French de-central obligation mechanism (including mainly generators but also demand response aggregators) considered that it did not provide sufficient incentives for new investment.

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

Cross-border participation would help increase competition and is necessary to correct distortions to locational investment signals that would otherwise be caused by the introduction of a de-central obligation mechanism. As with the central buyer mechanism this appears to be possible, although it has not yet been enabled in the examples covered by the sector inquiry.

6.2.6.3 Conclusions on de-central obligations

A de-central obligation mechanism has the potential to solve a general shortage of capacity efficiently, subject to appropriate eligibility criteria and a suitable capacity product. It does not require the amount of capacity needed to be centrally determined, which may be an advantage if market players are better suited to identify the needs for

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[121] The French mechanism includes an additional administrative element since suppliers' obligations are inflated by a 'thermosensitivity factor' to ensure suppliers buy enough capacity to meet demand in a particularly cold winter.

capacity. However, risk of over- or under-procurement exists, especially if penalties and other administratively-set parameters are not carefully designed.

If possibilities to contract on longer-term basis are limited, this may hinder the entry of new generators to the benefit of incumbent capacity providers. This is however not different to the situation in a market without any capacity mechanism where longer-term contracting is uncommon. Even where new entry is not immediately needed, mechanism designs that facilitate new entry can be useful to limit potential market power of existing capacity providers. The de-central obligation mechanism may therefore not be the most suitable in cases where there are concerns about barriers to entry and exercise of market power by incumbents.

6.3 Capacity mechanisms and the decarbonisation objective

The various types of capacity mechanisms have been assessed in this Staff Working Document mainly against their ability to address problems of generation adequacy and their potential to create distortions to the functioning of electricity markets. These two aspects correspond essentially to the policy objectives of security of supply and of efficient internal electricity markets.

However, as already explained in Chapter 2, current EU energy policy also encompasses the objective of decarbonisation. Significant private and public efforts have been made to advance in this area. By having an impact on generation capacity and on the generation technology mix, capacity mechanisms interact with policy instruments[122] designed to foster decarbonisation and may impact the achievement of their objectives. It is important that Member States, when they design capacity mechanisms are aware of these interactions, in line with the EEAG.[123] Chapter 5 of this Staff Working Document identified instances where eligibility or allocation criteria already take into account decarbonisation objectives.

6.4 Conclusions

From the discussion presented in this chapter, it emerges that a coherent and detailed generation adequacy assessment, showing the necessity of a certain amount and type of capacity as well as the timing and geographic extent of the adequacy problem is a critical

[122] For example the EU ETS.

[123] See para. 233(e) EEAG: " The measure should […] give preference to low-carbon generators in case of equivalent technical and economic parameters" and para. (220) "Aid for generation adequacy may contradict the objective of phasing out environmentally harmful subsidies including for fossil fuels. Member States should therefore primarily consider alternative ways of achieving generation adequacy which do not have a negative impact on the objective of phasing out environmentally or economically harmful subsidies, such as facilitating demand side management and increasing interconnection capacity."

step towards the identification of a particular capacity mechanism that may be compatible with state aid rules. A harmonised assessment which appropriately takes into account cross-border capacities may significantly reduce the need for financially support investment in capacity to ensure generation adequacy.

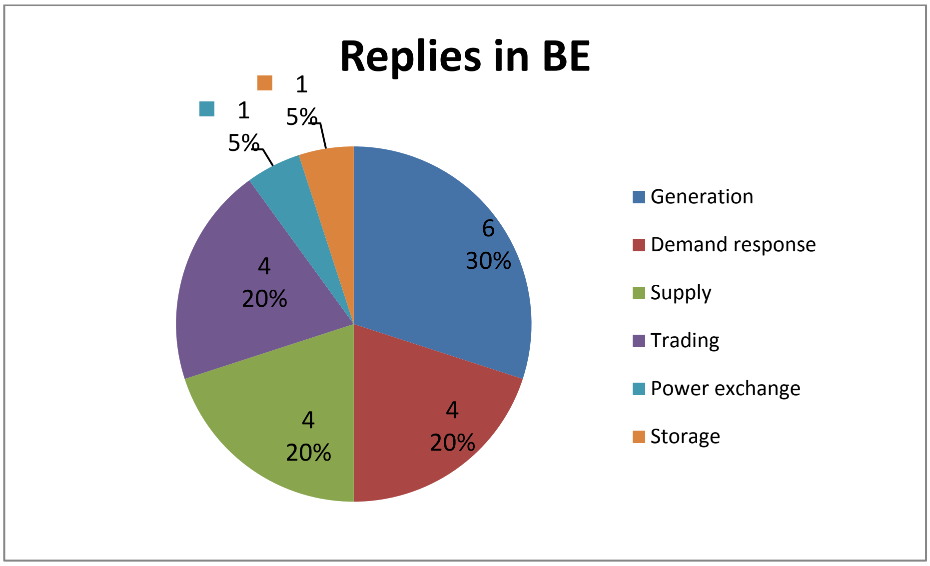
When a need for capacity mechanisms is identified, market-based competitive procedures are in general more likely to offer efficient tools to address generation adequacy problems than alternatives. Therefore, capacity payments models are the least likely to achieve their intended objectives in an efficient way. These models' reliance on administrative price setting comes with high risks of either overcompensation or insufficient volume being procured to meet the desired level of reliability.

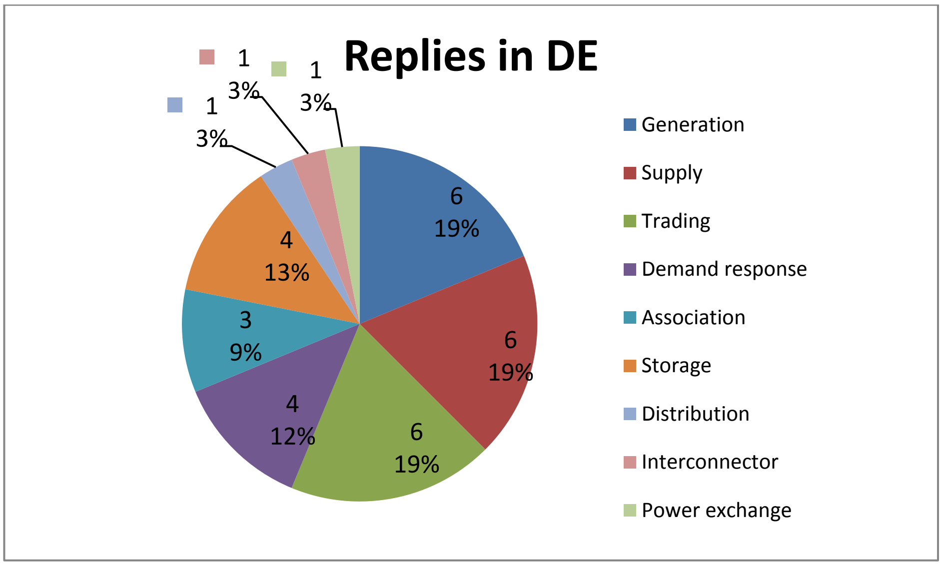
The remaining models are more likely to produce efficient outcomes, each one of them in distinct circumstances. The choice between these four types of mechanisms depends on the specific problem to be addressed.

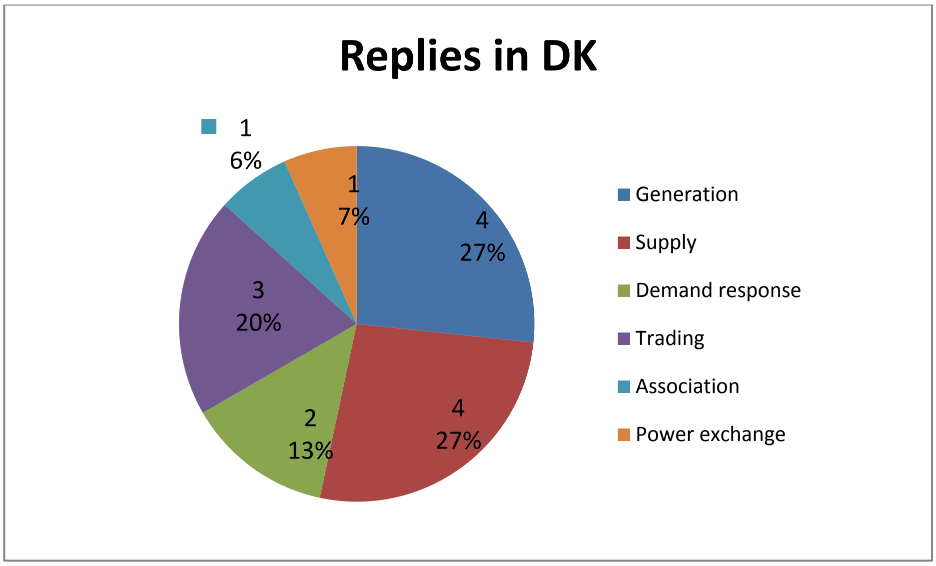
Tenders and strategic reserves can be appropriate tools to address a more immediate or transitional capacity problem. A tender allows new investment that may be undertaken faster than certain market or regulatory reforms, while a strategic reserve can keep existing plants from closing, which may be a good solution for a limited period of time. Interruptibility schemes can provide the TSO with an additional instrument to ensure grid stability and spur the development of demand response. These measures do not solve generation adequacy problems on a long-term basis, and can in fact worsen the situation if introduced without a clear plan to remedy the underlying problems in the longer term. However, they can bridge a gap until market reforms are made to enable the electricity market to provide sufficient investment incentives, or until a more appropriate longer-term capacity mechanism is introduced. Where these transitional or short-term solutions are deployed, they should be designed with as open eligibility criteria as compatible with their objective, and to minimise possible undesired distortions – for example by ensuring reserves are truly held outside the electricity market.

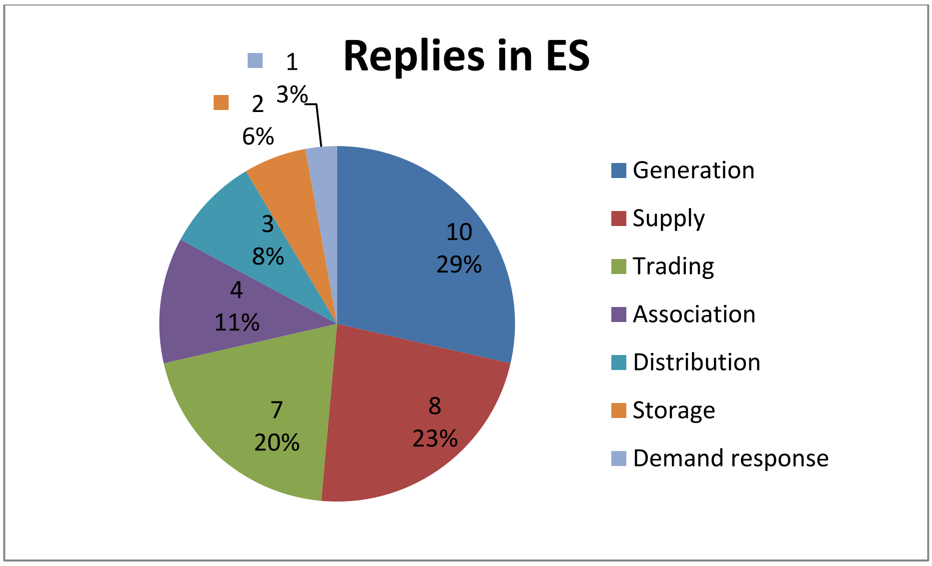
Central buyer mechanisms and de-central obligation mechanisms are the options that appear to be more appropriate to address a long-term, general problem of generation adequacy. Of these two options, the central buyer mechanism seems more appropriate to mitigate risks of market power abuse than the de-central obligation mechanism. To ensure the efficacy and efficiency of these types of mechanism, they need careful design including transparent, open and fair eligibility criteria and a capacity product that allows the electricity market to work with minimal distortions – including allowing electricity prices to provide a signal of scarcity so that electricity is imported at the right times.

ANNEX 1: TYPES OF RESPONDENTS PER MEMBER STATE





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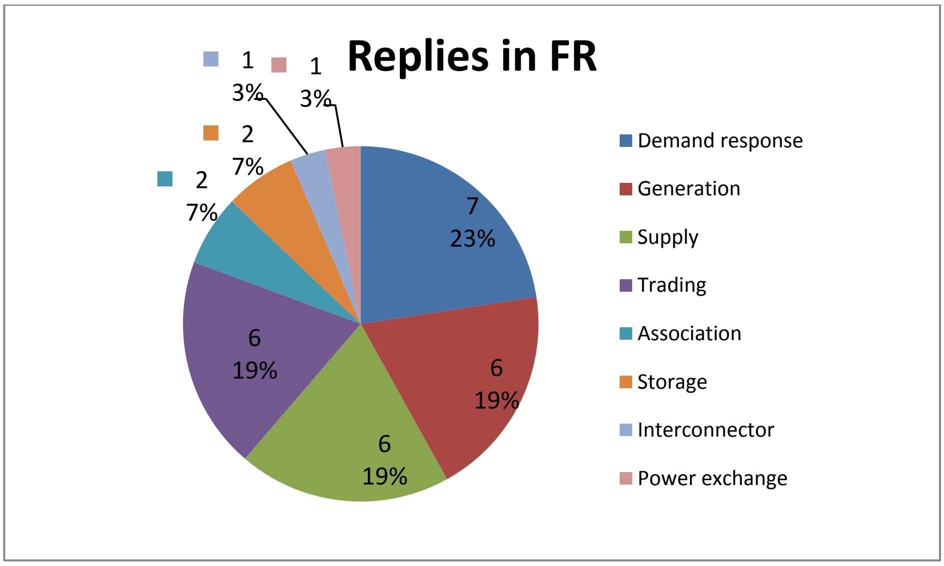
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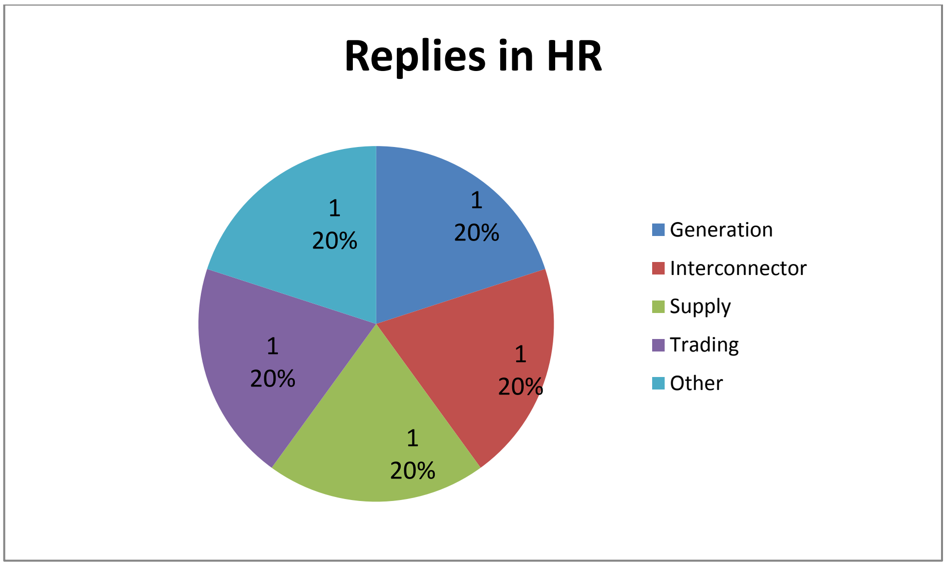
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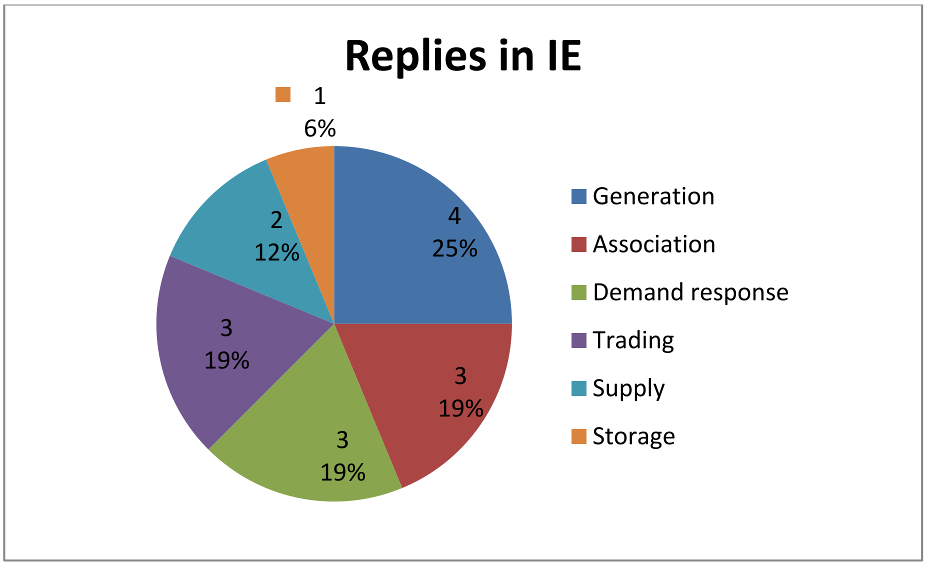

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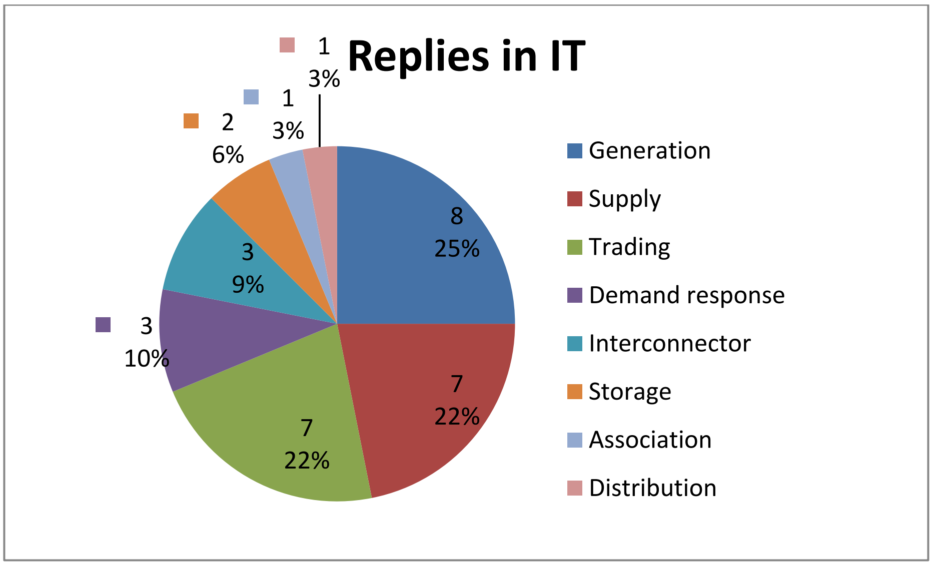

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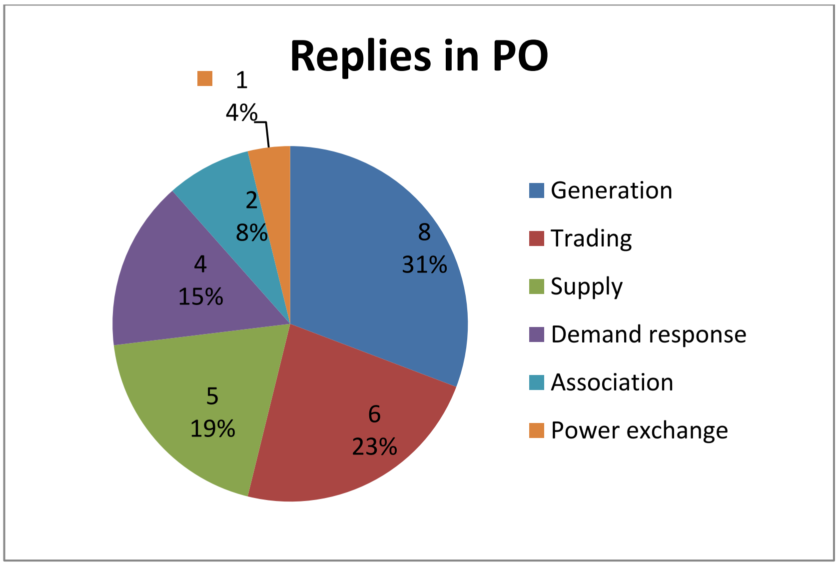

Replies in PO
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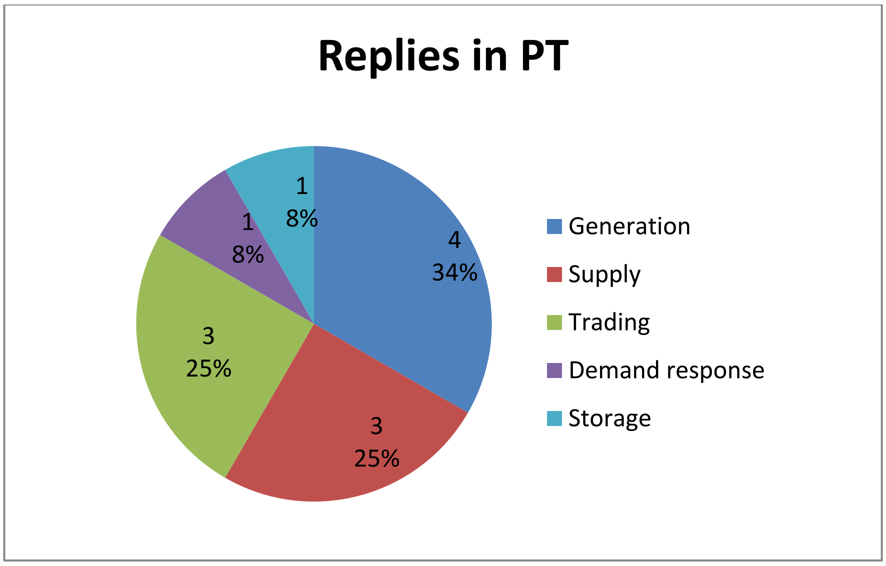
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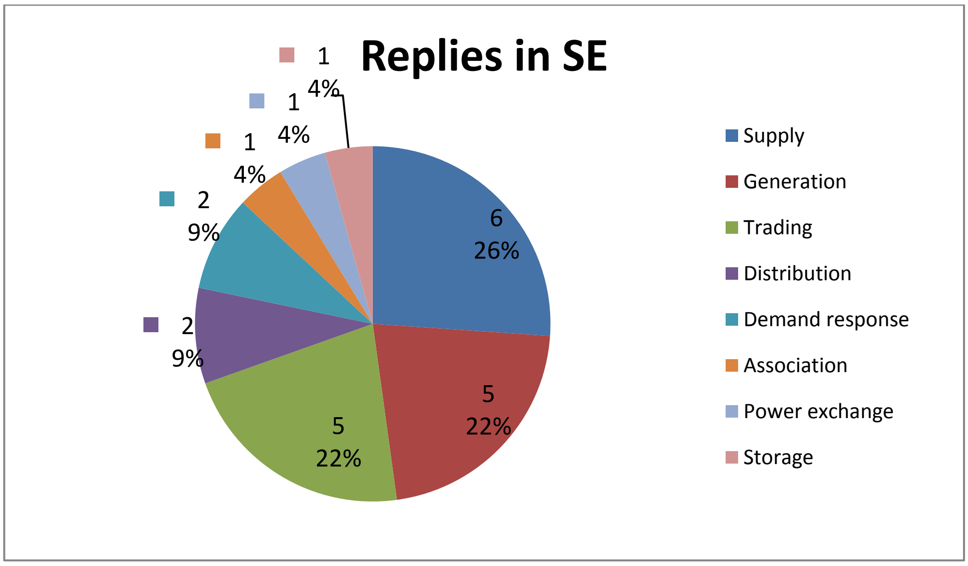
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Demand response
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Power exchange
Storage

ANNEX 2: MEMBER STATE WORKING GROUP ON THE PARTICIPATION OF INTERCONNECTORS AND/OR FOREIGN CAPACITY PROVIDERS IN CAPACITY MECHANISMS

This annex reports on discussions of a June 2015 working group of Member States that convened to examine the issue of cross-border participation in capacity mechanisms[124]. The material presented here is not a position of the Commission, and is not an outcome of the Commission's sector inquiry. This annex examines and aims to clarify technical aspects of effective cross-border participation in capacity mechanisms. The analysis presented here will form an input into the Commissions development of its Market Design Initiative[125]. The Commission intends to complement and further develop the analysis in this paper in that context.

The sector inquiry has found that cross-border participation is not yet enabled in the majority of capacity mechanisms, and with different Member States developing different solutions for their already different national capacity mechanisms there is an emerging risk of increasing fragmentation in the market[126]. The outcome of the working group with Member States is therefore presented below to stimulate discussion and support the development of solutions that could mitigate this risk.

This annex compiles the requirements in the Guidelines on State aid for environmental protection and energy (EEAG) related to the participation of interconnectors and/or operators in other Member States in capacity mechanisms, and recaps the importance of this aspect of capacity mechanism design (sections 1 and 2). Section 3 describes the challenges to accessing reliable capacity across borders, and section 4 identifies some of the main design questions that must be addressed by a Member State seeking a solution.

Section 5 considers the possible benefits of a more harmonised approach to this issue and presents the potential high level form that common rules could take and some of the questions that would need to be addressed to further develop such an approach. Given the number of Member States currently seeking to develop solutions for cross-border participation in volume based market wide mechanisms (France, Ireland, Italy and UK) the discussion in the working group and this paper focus primarily on the challenge of enabling cross-border participation in the central buyer and de-central obligation capacity

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124 More information on the working group, which also addressed other design questions related to capacity mechanisms, is available here: http://ec.europa.eu/competition/sectors/energy/state_aid_to_secure_electricity_supply_en.html

125 See Communication from the Commission launching the public consultation process on a new energy market design, COM (2015) 340 of 15.7.2015, notably question 20

126 See sections 5.2.2.6, 5.2.3.6, 5.2.3.7 and 5.2.3.8 of the detailed sector inquiry report.

mechanism types[127]. However, the other capacity mechanism models are also briefly discussed in section 6.

Views are sought on all aspects presented here, and suggested improvements and alternative ideas are welcome.

1. What do the guidelines require?

The EEAG include the following requirements related to cross-border participation in a generation adequacy measure:

(226) The measure should…take into account to what extent interconnection capacity could remedy any possible problem of generation adequacy.

(232) The measure should be designed in a way so as to make it possible for any capacity which can effectively contribute to addressing the generation adequacy problem to participate in the measure, in particular…

(a) the participation of…operators offering measures with equivalent technical performance, for example…interconnectors.

(b) the participation of operators from other Member States where such participation is physically possible in particular in the regional context, that is to say, where the capacity can be physically provided to the Member State implementing the measure and the obligations set out in the measure can be enforced (footnote: schemes should be adjusted in the event that common arrangements are adopted to facilitate cross-border participation in such schemes).

(233) The measure should:

(a) not reduce incentives to invest in interconnection capacity;

(b) not undermine market coupling, including balancing markets.

Figure A2.1: Summary of EEAG requirements related to the cross-border participation

Summary

[127] For a description of different capacity mechanism types, see Chapter 3 of the detailed sector inquiry report.

EEAG requirement	Objective
(226)	1. Should take the contribution of interconnection into account.
(232)	2. Should be open to interconnectors if they offer equivalent technical performance to other capacity providers. 3. Where physically possible, operators located in other member states should be eligible to participate.
(233)	4. Should not reduce incentives to invest in interconnection, nor undermine market coupling.

2. Aim of these requirements

The more participation in a capacity mechanism, the more competitive it should be and therefore the higher the chance that the mechanism provides value for money for consumers. This is why the EEAG include a general requirement for all types of capacity provider to be able to participate in capacity mechanisms.

If the contribution of imported electricity is not taken into account when capacity is procured through national capacity mechanisms, this would result in significant overcapacity. Note overcapacity will also result if the participation of cross-border capacity is not fully enabled[128].

If cross-border participation in capacity mechanisms is not enabled, there will be greater distortion of the signals for where new capacity should be built, and an increase in overall system costs. And capacity mechanisms will fail to adequately reward investment in the interconnection that allows access to capacity located in neighbouring markets.

If cross-border participation is enabled by requiring physical delivery of electricity into a particular market, or capacity payments are made (or penalties related to non-delivery are levied) per MWh to generators participating in a capacity mechanism, there is a risk that the market coupling rules (which ensure the most efficient use of interconnection) are undermined. There is also a risk of distorting the merit order in neighbouring markets.

Therefore the aim of these requirements is to maximise competition in capacity mechanisms, ensure efficient signals for investment in the right overall level of capacity

[128] The net benefits of avoiding self-sufficiency and making efficient use of the internal market for security of supply have been estimated at up to EUR 7.5bn per year in the period 2015-2030. See Booz & Co, 2013, 'Study on the benefits of an integrated European energy market': https://ec.europa.eu/energy/sites/ener/files/documents/20130902_energy_integration_benefits.pdf

in the internal market, and in the right types of capacity and network infrastructure where they are most needed, and enable market coupling to continue to deliver the most efficient use of existing resources in real time.

For the findings of the sector inquiry on the importance of cross-border participation in capacity mechanisms, please see section 5.2.3.6.

3. Background

3.1. Where does electricity flow at times of scarcity[129]?

In synchronous electricity networks, such as that in continental Europe[130], electricity flows to where it is demanded as long as the underlying network is strong enough. EU wholesale electricity markets are arranged into bidding zones, within which supply and demand is matched to create a single bidding zone price. These bidding zones should reflect the capacity of the underlying network to transport electricity. Within each bidding zone market participants are allowed to contract power with any capacity provider without limitations – ie. without accounting for any network constraints that might impact the ability to transfer power between sellers and buyers within the bidding zone.

Bidding zones in the European Union are being 'coupled', in line with the target model. Market coupling aims to ensure the interconnectors that link bidding zones are used most efficiently to send power between markets to where demand is greatest.

Most of Europe is now coupled day ahead with implicit allocation of cross-border transmission capacity. This means that prices and interconnector flows are jointly determined in a single step, for each hour of the following day. This is established through the matching of bids and offers across the power exchange/s operating in Europe. Roughly characterised, the prices for each hour in neighbouring markets are then compared, and the capacity of interconnectors is used to allow power offered in the lower priced zone to be matched with bids in the higher priced zone until either the prices in the two zones converge, or all available interconnection capacity is exhausted.

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[129] Throughout this annex the term 'scarcity' is used to indicate a situation in which a bidding zone has insufficient supply to meet demand. In a bidding zone where a capacity mechanism is in operation, the term also implies a situation in which contracted/certified capacity resources are required to meet their capacity obligations and there is the potential for penalties to apply.

[130] Alongside the continental European synchronous system, Norway, Sweden, Finland and part of Denmark operate a synchronous system, Great Britain operates as a synchronous system, as does the island of Ireland (Ireland and Northern Ireland). Latvia, Lithuania and Estonia are currently part of the same synchronous system as Russia, Ukraine and Belarus.

The Commission Guideline on Capacity Allocation and Congestion Management, which came into force in mid-August 2015, obliges each Member State to develop market coupling rules for day-ahead markets as well as intraday markets[131].

This price-matching process creates flow schedules for the interconnectors in real time. As intraday market coupling is introduced this will adjust any day ahead scheduling to reflect any differences in prices that emerge in intraday trading.

Figure A2.2 – Day ahead market coupling status in November 2015

REGIONAL DAY AHEAD IMPLICIT AUCTIONS		
	North West Europe (NWE)	Price coupling
	Poland	Poland price coupled within NWE through SwePol-link
	Ireland and Northern Ireland	All Island market, single price zone
	Czech – Slovak – Hungary-Romania	Price coupling

Source: APX, updated by the European Commission

Participants in coupled markets will continue to be able to buy hedging products: called 'physical transmission rights' (PTRs) and financial transmission rights (FTRs)[132].

Physical transmission rights will enable the holder to nominate a flow on the relevant interconnector at the day ahead stage. However, if this nomination is for a flow from a higher priced zone to a low priced zone and the price difference is sufficient, the market coupling algorithm will reallocate the full interconnector capacity (including the nominated amount) to flow power from the low to the high priced zone.

131 http://eur-lex.europa.eu/legal-content/EN/TXT/?qid=1445614788889&uri=CELEX:32015R1222

132 These will be defined in the guideline network code on Forward Capacity Allocation.

Financial transmission rights allow the holder to be paid the difference in price between two coupled markets, but do not give any nomination right or allow the holder to influence the flow of energy between coupled markets.

Although EU rules require TSOs to resolve network congestions without limiting commercial transactions (including across borders), TSOs can under certain conditions curtail nominations to preserve system stability[133]. Also relevant is Article 4(3) of the Security of Electricity Supply Directive[134], which states that 'Member States shall not discriminate between cross-border contracts and national contracts'. This rule requires TSOs to allow market coupling to determine flows, even if this means that in a situation where two coupled markets are both facing scarcity, the result of market coupling could be more severe scarcity in one country or zone because the price of electricity is higher in the neighbouring zone[135].

Market coupling is an effective way of ensuring the most efficient use of interconnection, but creates a certain challenge for enabling foreign participation in capacity mechanisms in Europe, because interconnectors have no influence over which direction power flows between markets, and individual capacity providers in a coupled market have very little influence on which direction power flows. With market coupling, it is not possible for a generator or demand response provider in a neighbouring zone to guarantee that its power will flow to consumers in another bidding zone. Under market conditions[136], power will flow to the bidding zone which offers the highest electricity price[137].

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133 See Article 16(3) of the Regulation (EC) No 714/2009 of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity of 13.7.2009.

134 Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006.

135 Curtailments of cross-border flows are nevertheless frequent, see ACER Monitoring Report 2014, page 162 (observing limitations of cross-border interconnection to solve internal congestion at 56% of all interconnectors). In its market design initiative and when developing network codes the Commission will further specify the framework for when Member States or TSOs can intervene in market transactions in response to emergency situations.

136 In emergency situations, Member States may intervene in the market-based coupling process and curtail cross-border flows; solutions for this situation are being developed in the framework of the market design initiative.

137 Once capacity mechanisms are introduced they will reduce the extent to which local electricity prices remunerate capacity. Capacity will be fully or partially rewarded separately through capacity payments.

The extent of this impact depends on how the capacity mechanism is designed. If a capacity mechanism acts as a replacement for high electricity prices at times of scarcity, there will not be an efficient signal for imports to the capacity mechanism zone at times they are needed. Nor will there be an efficient incentive for demand response participation in the electricity market outside the capacity mechanism. Distortions can

3.2. Which resources provide capacity across borders?

As explained in section 5.2.2.6 of the detailed sector inquiry report, the contribution foreign capacity makes to a neighbour's security of supply is provided partly by the foreign generators or demand response providers that deliver electricity, and partly by the transmission (interconnection) allowing power to flow across borders. Depending on the border, there can be a relative scarcity of either interconnection or foreign capacity.

This further complicates the design of an efficient solution for enabling cross-border participation in capacity mechanisms since it requires the chosen design to enable an appropriate split of capacity remuneration between interconnector and foreign capacity to reflect the relative scarcity of each. It also ideally requires this split to adapt over time – for example through a design that increases the reward for foreign capacity and reduces the reward for interconnection if over time the proportion of interconnection increases.

4. Main design options – overview

4.1. Consideration of imports in the generation adequacy assessment

When the demand requirement is set in a capacity mechanism, the total capacity demanded can be adjusted to account for expected imports (at times of scarcity). This is sometimes called 'implicit participation'. This reduces the risk of domestic over-procurement and recognises the value to security of supply of connections with the internal energy market - the interconnection-related aim of EEAG 226. However EEAG 232 requires explicit cross-border participation (see 4.2 below). Implicit participation does not remunerate foreign capacity for the contribution it makes to security of supply in the capacity mechanism zone. If only domestic capacity receives capacity payments, there will be a greater incentive for domestic investment than investment in foreign capacity or interconnectors resulting in less than optimal investment in foreign capacity and in interconnector capacity.

For the GB Capacity Market (SA.35980), the UK used implicit participation for the first year of operating the mechanism, but the approval of the scheme included a commitment that from the second (2015) auction interconnected capacity would be able to directly participate in the Capacity Market. In the second auction that took place in December 2015 interconnectors were admitted and were secured 4.2 GW of capacity agreements, corresponding to approximately 9% of the total auctioned capacity[138].

4.2. Explicit cross-border participation

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be reduced by ensuring that the electricity market continues to function effectively even if a capacity mechanism is introduced.

[138] National Grid, 'Provisional Auction Results: T-4 Capacity Market Auction for 2019/20', Figure 4.

If the locational investment signals are to be corrected, the contribution of imports to the capacity mechanism zone must not only be identified, but the providers of this foreign capacity need to be remunerated for the security of supply benefits that they deliver to the capacity mechanism zone. This requires the 'explicit participation' of foreign capacity in the capacity mechanism.

This section considers four aspects of design that need to be considered in an explicit participation solution:

- Identifying the amount of foreign capacity that can participate / receive remuneration, through establishing the contribution of potential interconnector and foreign capacity participants.

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

- Identifying the counterparty for a cross-border capacity contract – ie. interconnectors, foreign capacity providers, or both could be signed up to capacity contracts.

- If foreign capacity providers are to participate, which foreign capacity providers should be eligible?

4.2.1 Establishing the contribution of interconnectors and foreign capacity

The EEAG require the inclusion of foreign capacity 'where the capacity can be physically provided to the Member State implementing the measure'. It may therefore be justifiable to exclude providers if it can be shown that their location means they could never be expected to deliver the required service. Effective cross-border participation requires an evaluation of the expected actual contribution of a capacity provider at times when it is required. This evaluation is often referred to as 'de-rating'.

- If cross border capacity is the counterparty, unlike for domestic capacity[139] the required evaluation would include assessing not just the capacity provider's ability to provide electricity when needed, but also their access to interconnection capacity.

- If interconnectors participate directly as a counterparty then their available capacity needs to be calculated.

Calculation of the availability of interconnection capacity is critical as conservative assumptions will lead to overcapacity, and overly generous assumptions could lead to adequacy standards not being met.

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[139] Though domestic capacity also requires domestic network access.

The technical capacity of interconnectors represents the maximum amount of power which can flow through the interconnector at any one time. There is always some probability that this will not be available – either because of the technical availability of the interconnector, and/or because the technical capacity of the interconnector can be used to flow electricity both as imports to the capacity mechanism zone, but also as exports from the capacity mechanism zone, depending on the balance of supply and demand in the zones connected by the interconnector. Therefore it may be necessary to de-rate the interconnectors according to expected contribution to the capacity mechanism zone at times when imports are needed to avoid scarcity[140].

However, interconnectors can flow power in two directions, and the same generation (or demand response) assets can contribute to security of supply in two regions if peak demand occurs at different times. In fact this is one of the chief security of supply benefits of the internal market. Conversely, if peak demand occurs at the same time, the generation (or demand response) assets can only benefit one of the regions (see Box A2.1 for a more detailed explanation).

Box A2.1: How much do interconnectors contribute to security of supply?

The interconnector's technical availability is one important consideration (ie. is the line itself operational or not?). The long term average technically available capacity of the interconnector could be identified and offered to participants seeking to sell capacity into a cross-border capacity mechanism[141]. This de-rating should reflect the extent to which the interconnector is expected to be unavailable for maintenance or otherwise technically unavailable at times of scarcity.

However, the extent to which an interconnector can reliably provide imports to the countries it connects depends not just on the line's technical availability but also on the potential for concurrent scarcity in the connected markets.

If zone A only has a winter peak demand problem and connected zone B only has a summer peak demand problem, each may expect 100% imports from the other at times of local scarcity. However, if countries A and B are neighbours with similar demand profiles and some similar generation types there may be some periods of concurrent scarcity where neither can expect imports from the other.

140 Note an alternative capacity mechanism design might enable participants to 'self de-rate' rather than relying on central de-rating. Such a design may require high penalties with no or very limited exceptions and a robust testing regime to avoid participants selling more capacity than they could reliably provide, but could avoid the difficulty of centrally establishing appropriate de-rating.

141 The interconnector's technical availability must already be assessed in the context the CACM Regulation, where tradeable capacities for the different market timeframes are determined in a comprehensive way.

Where two connected markets both operate capacity mechanisms, one approach would be to take the full capacity of the interconnector and allocate it between the two connected capacity mechanisms. This would enable capacity providers to make a choice between participation in either their domestic capacity mechanism or a neighbouring one. For example, if there was a 2GW link between zone A and zone B, 1.5GW of capacity could end up being sold to providers located in B wishing to participate in the capacity mechanism of zone A, and 500MW to providers located in A wishing to participate in the mechanism of zone B.

The problem with this approach is that, with the two markets considered together as a system, the interconnector is assumed to make a net zero contribution to security of supply. In this situation, the domestic capacity demanded in the national capacity procurement process in zone B would be increased by 1 GW to compensate for the net capacity contracted to deliver cross-border to zone A. This would only be an efficient outcome for the system if zone A and zone B always experienced coincident scarcity and the interconnector indeed delivered no net security of supply benefit.

In practice, however, it is extremely unlikely that scarcity events will be perfectly correlated between two neighbouring countries. So, to avoid a situation where overall less value contribution by imports to security of supply is assumed for imports than is truly the case, a statistical judgement – de-rating of the interconnector/s on each border to reflect expected maximum long-run average import capacity at times of scarcity – is needed for each capacity mechanism about the value of imports at times of scarcity[142]. The amount of capacity demanded domestically should be reduced by this amount, and this capacity is then available for allocation to foreign capacity providers.

It is in consumers' interest to ensure the full value of interconnection is taken into account, otherwise excess capacity will be built across Europe at unnecessary cost. De-rating of resources across borders will likely require good cooperation between TSOs, and common rules or guidance on de-rating of interconnectors may be required. It may be necessary to task ENTSO-E with establishing common principles for de-rating and the appropriate methodology for calculating suitable capacity figures for each border.

It may also be necessary to task ENTSO-E with coordinating work to establish common rules for the de-rating of foreign capacity resources for the purpose of participation in capacity mechanisms, so that a MW of capacity in each country/zone is comparable.

In addition, to ensure judgements about the level of imports that can be expected are not overly conservative, it may be necessary to define common rules for all TSOs to apply in scarcity and emergency situations, and for example exactly what procedures are followed when there is concurrent scarcity in two neighbouring markets. This work also appears essential to prevent any contradiction between TSOs' rules and the requirements of EU law in relation to cross-border electricity trading.

4.2.2 Obligations and penalties for interconnector / foreign capacity

As discussed in section 5.4 of the detailed sector inquiry report, there are various ways of designing obligations and penalties in a capacity mechanism.

Capacity providers may be required to either be available by declaring that they are available to the TSO, or by placing a bid to deliver electricity, or they may be required to verify their availability by actually delivering electricity regardless of whether the market price is sufficient to cover their running costs. For cross-border capacity, a delivery requirement could require a foreign capacity provider to deliver electricity into its local market, or it could require that capacity provider to deliver electricity in its local market <u>and</u> require the interconnection between the two markets to be sending electricity towards the market where the capacity mechanism is operating. With market coupling in operation, however, it is clear that an individual foreign capacity provider will in most cases have a very minor influence on the direction of flows across an interconnector (and the interconnector operator would have no influence over the flow direction).

Different capacity mechanisms also apply different penalties when obligations are not met. They could apply a flat rate financial penalty, for example, or a penalty linked to the value of lost load. Over delivery payments may also apply – as is increasingly seen in US markets operating the 'pay for performance' principle.

In principle, if the allocation process for capacity contracts allows interconnector or foreign capacity to compete directly with domestic capacity, the obligation and penalties faced by the interconnector or foreign capacity providers should be the same as the obligations and penalties faced by the domestic capacity providers.

However, there are issues with imposing obligations and penalties on interconnectors or foreign capacity providers. In particular, in coupled markets even if foreign capacity providers face additional incentives from a capacity mechanism to deliver capacity into their local market, in most cases this will not significantly increase the chances of delivery in a particular direction across a constrained interconnector.

Any obligations, penalties or over delivery payments that result in the delivery of capacity that would not otherwise have delivered may impact on market coupling. For example, if a generator in zone B is penalised if not delivering energy into zone B whenever there is scarcity in zone A, this means that generator's decision to run is no longer based only on its marginal costs and the price of electricity in zone B. It is also based on the cost of the penalty that will be levied by the zone A capacity mechanism if it does not produce. This could create additional distortions since it may mean this plant runs out of merit, displacing other plants in the local merit order.

In practice, in a situation where there is scarcity in zone A and the possibility of penalties for capacity providers located in zone B participating in zone A's capacity mechanism, the price in zone A should rise high enough to ensure the interconnector flows 100% in the direction of zone A. In this situation a delivery obligation on the capacity providers in zone B would have no impact.

Some obligations, testing and penalties may still be required to ensure that foreign capacity is at least a verifiable and reliable source of capacity in its local market. But because of the potential for delivery obligations to create distortions and the fact that anyway such obligations can only incentivise actions which are likely to have a very limited effect on cross-border flows, delivery obligations may not be appropriate for interconnectors or foreign capacity. Establishing a relatively simple availability product instead makes cross-border participation much more readily implementable and avoids creating distortions to merit order dispatch that might be created with delivery obligations.

Another issue that will arise with cross-border participation is the need to levy penalties on foreign resources. There appear to be various ways in which this could be enabled, for example through an appropriate governance regime tied to the agreement to participate in the capacity mechanism.

4.2.3 Counterparty for a cross-border capacity contract

The Third Energy Package and EU Network Codes require that interconnectors are treated as transmission capacity, and fully unbundled, and that the flow of energy across borders is determined solely by electricity price differences. Member States are however considering explicit participation designs that enable the direct participation of interconnector operators, foreign capacity, or a combination of the two.

As identified in the sector inquiry and explained in section 3.2 of this annex, an efficient design for cross-border participation should ensures the revenues from the capacity mechanism that end up being paid to the interconnector and the foreign capacity reflect the relative contribution each makes to security of supply in the zone operating the capacity mechanism.

Including foreign capacity providers directly in a capacity mechanism can reveal the value (from a generation adequacy perspective) of additional interconnection capacity. For example, if a zonal auction for capacity in a neighbouring zone cleared at a lower level than the main capacity auction, the difference between the two clearing prices would reflect the value of increased interconnection capacity between the two zones. Member States should ensure that interconnection investment reflects these signals. This could be achieved by rules ensuring that the interconnector could receive the difference between the zonal capacity prices[143]. This would mean that the principle of separation of generation and supply from network operation could be maintained. Competition should ensure that if there is plentiful supply of cheap capacity in the neighbouring market relative to the amount of interconnection, then the interconnector receives most of the capacity revenue – sending signals for investment in more interconnection[144].

If capacity contracts are awarded directly to an interconnector operator, the extent to which foreign capacity is appropriately rewarded may depend on the obligations and penalties associated with the capacity contract. With a delivery obligation (obligation for power to flow to the capacity mechanism zone at times of scarcity) and high enough penalties, the interconnector may seek to contract with capacity providers in the connected market to pass on the delivery risk to counterparties better able to manage this risk (since the interconnector operator has no control of the direction in which electricity flows) and capacity providers in the connected market at least have some influence (though this may also be marginal)[145]. However, in a model with interconnectors as a counterparty with a capacity payment for availability and no delivery obligation (or obligation to 'subcontract' with foreign capacity providers) it is not clear how appropriate revenues would be awarded to foreign capacity providers. In this model, it seems likely that all the capacity revenue would accrue to the interconnector itself, regardless of the relative scarcity of interconnection and foreign capacity.

In some situations there may be a justification for including interconnectors as a counterparty – for example, where there is a very large supply of foreign capacity and the interconnector is clearly the scarce resource. But the concern in the previous paragraph, combined with the potential distortions of imposing delivery obligations across borders (see section 4.2.2 of this annex), probably means that the most efficient solution would require foreign capacity to participate directly across borders, rather than the interconnector participating.

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[143] Just as for congestion rents earned where electricity prices differ in neighbouring interconnected markets. For regulated interconnectors, any capacity congestion rents earned would need to be appropriately regulated (eg. refunded to consumers in the connected markets if the interconnector's revenues – including the capacity revenues – are above its regulated cap). See Regulation 714/2009 Articles 16 and 17.

[144] If there is abundant interconnection capacity and not much foreign capacity available, the foreign capacity would receive the bulk of the capacity revenues – sending signals for increased investment in foreign capacity. Likewise, if capacity can be most efficiently provided by building more domestic capacity this should be the outcome – signalled by the foreign capacity bidding too high to be competitive in the neighbouring capacity mechanism.

[145] In addition, any such hedging by interconnector operators may be challenging to enable in compliance with the restrictions on trading activity by interconnector operators under the rules of the third package. See Directive 2009/72/EC Chapter IV.

4.2.4 Which foreign capacity providers should be eligible?

In principle the same eligibility rules as apply in the domestic market should apply to foreign capacity – with foreign demand response and storage eligible to compete alongside generation[146].

A major question to address is whether capacity providers should be able to offer capacity into more than one capacity mechanism for the same time period. Limiting participation to a single mechanism might at first sight appear to be necessary. This approach would however lead to system-wide over procurement if every zone in the system operates a capacity mechanism (assuming the capacity mechanisms require people to fulfil a capacity obligation at any time for eg. the winter, or for the whole year).

This example illustrates the problem:

- Zone A wants to buy 10GW of capacity. It wants it to be available all year.
- Zone B wants to buy 10GW of capacity. It wants it to be available all year.
- There is 5GW interconnection between these two zones.
- Zone A identifies that it can count on 4GW of imports from B at times of scarcity in A.
- Zone B identifies that it can count on 2GW of imports from A at times of scarcity in B.
- Zone A procures 10GW of capacity. It might procure up to 4GW of this from zone B if the capacity there is cheaper.
- A month later, Zone B procures 10GW of capacity. If participation was only allowed in one capacity mechanism, Zone B could only procure the 10GW from resources that have not contracted to provide capacity to zone A.
- The total capacity procured by A+B would be 20GW. So unless there was perfectly correlated scarcity between A and B there would be over procurement. Also, if both countries had an equally attractive capacity mechanism then in practice there would probably be no cross-border participation.

Therefore, to avoid system-wide over procurement, the participation of capacity providers in more than one capacity mechanism for the same time period must be enabled.

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[146] Harmonised rules for de-rating, baselining, testing and verifying demand response may need to be developed to enable this although we recognise that this is difficult even at national level as individual DNOs often have their own procedures.

4.3. Issues for consideration

- Although it mitigates some negative effects, simply accounting for imports when establishing demand for capacity does not actually enable cross-border participation in a capacity mechanism.
- Cooperation between TSOs may be needed to establish common rules for adequately de-rating cross-border resources and calculate transmission capacities for cross-border participation in CRMs.
- Common and transparent rules for Member State and TSO actions in scarcity and emergency situations are required to avoid the current lack of trust about the potential for imports at times of concurrent scarcity.
- Availability obligation models probably do not distort market coupling, nor distort foreign markets (except possibly for some distortions due to any required testing).
- With the interconnector as counterparty, it is not clear that an availability model delivers appropriate revenues to foreign capacity providers.
- The most appropriate design choices may therefore be to enable foreign capacity to participate directly, with availability rather than delivery obligations imposed on the foreign capacity providers and the interconnector operator.
- To avoid system-wide over procurement, capacity providers must be able to participate in more than one capacity mechanism for the same time period.

5. Towards a common approach to integrate volume based market wide capacity mechanisms

Designing appropriate rules for cross-border participation in capacity mechanisms is challenging. Given the different capacity mechanism designs already emerging across Europe, there may be value in developing common rules at least for cross-border participation in these different mechanisms. Building on the design options presented above, this section presents, a potential high level approach to cross-border participation in capacity mechanisms.

Although a harmonised capacity product used in each national capacity mechanism would no doubt simplify the design challenge and potentially increase overall efficiency by simplifying the range of rules investors, market participants, regulators and system operators across Europe have to understand, a harmonised product is not necessarily a pre-requisite for cross-border participation in capacity mechanisms. However, a harmonised set of principles or rules <u>specifically for cross-border participation</u>, including defining a common product to account for the capacity to be supplied from neighbouring markets may be required to facilitate cross-border participation[147].

Although there would be a cost to the time spent developing and implementing such a proposal, it could deliver a number of benefits, for example:

i) reducing complexity and the administrative burden for market participants operating in more than one zone.

ii) removing the need for each MS to design a separate individual solution – and potentially reducing the need for bilateral negotiations between TSOs.

iii) enabling the link with market coupling to be addressed jointly – and ensuring the rights of MS with and without CMs are protected.

iv) leaving market coupling and all the work on the target model intact and ensuring that the distortions of uncoordinated national mechanisms are corrected and the internal market able to deliver the anticipated benefits to consumers.

5.1. High level approach

One way to achieve the above benefits could be to:

a) Define the way in which the amount of imports that can be relied upon at times of scarcity in each zone operating a capacity mechanism should be calculated (interconnector de-rating);

b) Identify the capacity providers that could be eligible to provide capacity into a capacity mechanism in a neighbouring market;

c) Define the obligations and penalties that would apply to those who hold capacity contracts in relation to a capacity mechanism in a neighbouring market;

d) Define a competitive process for offering this import capacity to eligible capacity providers;

e) Define rules for the trading of this import capacity once allocated;

f) Define any obligations and penalties applicable to the interconnector operator, including rules on the enforcement of penalties across borders;

g) Influence flows in the direction of the capacity mechanism if market coupling cannot deliver sufficient certainty;

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147 Note such a product would not necessarily match the product contracted in the different capacity mechanism/s connected by these common rules.

h) Allocate the costs of foreign capacity to consumers;

i) Appropriately remunerate the interconnectors that enable the participation of cross-border capacity; and

j) Ensure compliance of TSOs.

Market-based rules for participation in capacity mechanisms should complement European rules for effective coordinated management of actual simultaneous *physical* scarcity situations in the grid.

Following the analysis in the first half of this annex, the presented model is based on foreign capacity providers participating directly across borders, rather than involving the direct participation of interconnection. In addition, the capacity product is based on availability rather than delivery.

5.2. a) Interconnector de-rating

As explained in section 4.2.1 of this annex, a statistical judgement – de-rating of the transmission capacity across each border to reflect expected maximum import capacity at times of scarcity – is needed for each capacity mechanism. The amount of capacity demanded domestically would be reduced by this amount, and this capacity is then available for allocation to foreign capacity providers.

5.3. b) Eligible foreign capacity providers

The eligibility of foreign capacity, and any de-rating applied, could be decided based on the criteria in the capacity mechanism for which capacity is being procured, or common rules could be established. The determined eligibility in either case would need to meet the requirements in the EEAG requiring all potential capacity providers to be able to participate[148].

As explained in section 4.2.4 of this annex, to avoid overcapacity in the system, individual capacity providers could be eligible to offer their capacity into more than one capacity mechanism for the same obligation period.

Common rules and methodology requiring TSO cooperation in the de-rating of capacity in neighbouring markets are likely to be beneficial to ensure that a MW of capacity has comparable value regardless of its location.

A common registry may be helpful to facilitate de-rating and any certification, pre-qualification and testing of foreign resources, and could also facilitate secondary trading of capacity contracts.

[148] See http://ec.europa.eu/competition/sectors/energy/capacity_mechanisms_working_group_4.pdf

5.4. c) Obligations and penalties on foreign capacity providers

Given the potential distortions that could arise with a delivery obligation, the obligation on capacity providers would likely need to be a relatively simple availability obligation. Ideally, this would be developed in cooperation with the neighbouring TSO, however, even without such cooperation suitable a suitable product definition might be found enabling the verification of availability without requiring any obligations that might introduce distortions to neighbouring markets. A local market bidding requirement might be one way of enabling a foreign capacity provider to demonstrate that they have made capacity available – though further consideration would be needed to determine exactly how an individual plant bid might be distinguished from the bids of all generators in a portfolio. Careful design of the availability obligation and no or very limited exceptions to it, along with a clear set of procedures for cooperation (and any appropriate remuneration) between TSOs for testing capacity resources would be required to ensure the reliability of contracted resources (and avoid the problems encountered in US markets with resources paid for availability and benefitting from various exceptions)[149]..

Following the de-rating rules described above, each participant would be required to make available its full de-rated capacity in periods in which there was scarcity in the foreign capacity mechanism.

In a model where capacity providers could choose to sell into more than one capacity mechanism, the penalties that apply when they do not provide the contracted service would serve an important function in ensuring participants have the right incentives to participate – or not – in more than one mechanism.

A capacity provider that has sold capacity into the domestic capacity mechanism and a foreign capacity mechanism would need to meet its obligation to both mechanisms to avoid paying a penalty. Assuming the capacity provider is reliable, this could be possible if scarcity events in the connected markets are not correlated, since the obligations would not overlap. However, if a capacity provider has chosen to sell into two capacity mechanisms and there is an hour of concurrent scarcity:

- If they meet their domestic obligation, unless they also make available enough capacity to the local market to meet their foreign obligation, they would need to pay a penalty to the foreign capacity mechanism zone.

- If they fail to meet their domestic and foreign obligations, they would need to pay two penalties – one to the domestic capacity mechanism and one to the foreign capacity mechanism.

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[149] See section 5.4.2.3 of the detailed sector inquiry report for more on this..

The participation in more than one capacity mechanism, even if two penalties could be applicable, raises a question about potential overcompensation. If there is no concurrent scarcity, there is no overcompensation to these providers because they help resolve scarcity in both / all markets. However, if there is concurrent scarcity, then with insufficient penalties there is a risk of overcompensation to generators that sell into more than one mechanism. And the general direction in capacity mechanism development seems to favour verifiable physical capacity and relatively low penalties supported by testing[150], rather than high penalties.

However, any potential overcompensation should be eroded by competition – ie. participants should be willing to commit to an additional capacity obligation at a low price if the reward exceeds the risks. This should mean the price for foreign capacity would be competed down to a low level and most of the revenue would go to the interconnectors rather than the foreign capacity. If in fact the risk of concurrent scarcity turned out to be higher than expected, the price in future should adjust so that a higher share goes to the capacity providers. This should help ensure the allocation of capacity value between interconnectors and foreign capacity providers would remain a reliable signal of the relative contribution each makes to security of supply[151].

Allowing capacity providers to participate in more than one mechanism would also act as a way to reveal any overly conservative central assumptions that were made about the chance of concurrent scarcity and therefore the level of imports that should be expected across each border. However, the central determination of the maximum amount of foreign capacity that can participate in a capacity mechanism plays an important role in ensuring that the overall level of system security required by Member States is reached. In other words, the level of security provided by the foreign capacity should not be affected by the possibility of capacity selling into multiple mechanisms because each zone has in any case limited the amount of foreign capacity that can participate. The level of security in a model with the potential for explicit participation of capacity providers in

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[150] This seems to be for two reasons: i) political reasons, where there are suggestions that politicians responsible for security of supply wish to have a verified / proven source of capacity contracted, rather than a capacity mechanism potentially being open to financial market participants; and ii) to enable financing, since the potential for high penalties may mean capacity contracts are less suitable as a basis for seeking financing.

There may also be an added benefit of relatively low capacity mechanism penalties in that they leave space for the underlying electricity market to provide the main signal for flexibility (through high prices when electricity is scarce). This enables the electricity market to continue to provide the import signals required for the efficient operation of the internal market.

[151] In a system where capacity providers were only able to participate in a single capacity mechanism, competition in this price setting process would be artificially constrained and the allocation of costs would be less reliable.

more than one capacity mechanism is in fact the same as the level of security provided by a statistical (implicit) approach to interconnector participation.

Any capacity obligation should be complemented by robust penalties for non-availability. At a minimum, parties that consistently fail to meet their obligation should be able to lose 100% of any revenue earned through capacity contract payments (though this may not be sufficient and higher penalties may be required, particularly to ensure participants make a sensible judgement about the possibility of participating in more than one mechanism). As a starting point for discussion, the penalty applicable to foreign capacity that fails to meet its cross-border obligation could be set at the imbalance settlement price in the capacity mechanism zone applying the penalty for each MWh not made available. Capacity providers could reduce any penalty due by trading with other capacity providers that are available and not delivering into the local capacity mechanism.

With different capacity mechanisms in Europe already applying different contract lengths, it may not for the time being be possible to choose a single rule for cross-border capacity that matches each current national model. However, short contracts for cross-border participation would avoid fixing the remuneration between interconnectors and foreign providers for long durations, and allow more easily for future adaptation or removal of the cross-border participation model if required. It would also ensure that the de-rating of an interconnector or the ‘expected imports’ from a particular market could be updated annually to account for changing dynamics within that market and more closely reflect the real contribution of imports.

More granular time-bound products may also be appropriate – for example to allow capacity providers to deliver capacity for one period (eg. during summer but potentially even for specific balancing periods) in one mechanism, and another period in another mechanism. These more granular products could emerge through secondary trading.

5.5. d) Trading of cross-border capacity

Under the present approach, foreign capacity providers would be able to trade their capacity contracts within the same bidding zone to allow them to manage risks of changing circumstances (for example required maintenance or unplanned outages). Foreign capacity providers would therefore be free to trade their contracts to other eligible providers that have not already sold all of their (de-rated) capacity into the relevant capacity mechanism (ie. the mechanism for which the contract is being traded). Some kind of registry and/or notification procedure is likely to be required to enable this.

5.6. e) Obligations and penalties on interconnector operators

Under the present approach, interconnectors would have an obligation to be operational (technically available) at times of system scarcity in either connected zone. Interconnectors have no control over the direction of flows on the interconnector so it would not seem justified to penalise them if the flows over the interconnector are not what was expected when the de-rating based on expected flows was carried out. However, the risk of interconnector operational availability is mainly within the control of the interconnector operator. If not technically available, they should therefore face the same penalty as foreign capacity providers (and foreign capacity providers should not be penalised in periods when the interconnector is unavailable).

Since interconnector operators would potentially be 'involuntary' participants in each measure and would have no direct control over the capacity price they receive (since the price left for interconnection would be determined by the voluntary bids of foreign capacity providers to participate) it would be appropriate to cap the maximum penalties that could be levied on interconnectors for lack of availability.

5.7. f) Competitive cross-border bidding process

The import capacity established for each interconnector (into each capacity mechanism) could be competitively allocated in various ways:

- explicit auction: where TSOs (or exchanges, or even the interconnector operators) auction the available cross-border capacity in advance of any capacity allocation process within a national capacity mechanism. Effectively, they would be auctioning a ticket allowing entry into the related capacity mechanism, in the same way as interconnector capacity can be auctioned explicitly – separately from electricity. Those successful in the ticket auction would then be able to bid into the capacity auction in the related capacity mechanism (if a central buyer model) or offer their capacity in the market to suppliers needing to fulfil their obligations (if a de-central obligation model).

- implicit auction (central auction model): where foreign capacity bids directly into a national capacity auction, which establishes a price for each cross-border capacity zone. This is similar to the way interconnector capacity is implicitly auctioned along with electricity in coupled markets.

- implicit auction (de-central obligation model): where an auction is held in which foreign capacity providers offer their capacity and domestic suppliers offer to buy it. This could for example be hosted on an exchange.

- direct selling to suppliers (only in a de-central obligation model): where foreign capacity providers offer their capacity directly to suppliers in a capacity mechanism seeking to fulfil their obligation. Exchanges may be able to help limit trade to the maximum import capacity – for example if foreign capacity providers were required to trade only on exchanges. Ensuring the interconnector operator also receives remuneration for its service could be challenging in such a system. It might be possible for the interconnector to offer a 'capacity rights' product on an exchange, and for capacity providers to be required to simultaneously buy these capacity rights at the same time as an offer to provide capacity is accepted. If the transactions cannot be concluded simultaneously some basis risk (see below) will remain.

With an explicit auction, the gap between the entry ticket auction and the domestic auction would create an additional risk ('basis risk') for participants, since when competing in the ticket auction they would be uncertain about the value of capacity in the system for which they were bidding to participate. This could result in a lower price being bid for the entry tickets to compensate for this risk and/or reduced competitive pressure, as this risk presents a barrier to entry.

An implicit auction appears likely to be the most efficient solution since it eliminates any basis risk.

5.8. g) Influencing interconnector flows (without distorting market coupling)

Market coupling combined with more integrated balancing markets should ensure electricity flows where it is needed in times of scarcity. Member States should take the necessary steps to ensure market rules function in this regard by implementing the third package, including applying network codes and ensuring balancing markets work properly and electricity prices can rise to reflect scarcity.

In the event of a scarcity event in two Member States at the same time that brings prices to in both markets to the market coupling price caps (currently EUR 3000 per MWh for the purposes of day ahead market coupling and below most estimations of the value of lost load) rules could be developed to enable electricity flows in proportion to cross-border capacity contracts held rather than the current default of equal sharing of curtailment. However this would only be appropriate as long as the market coupling price cap is significantly lower than the value of lost load, as otherwise such a system would discriminate against energy only markets.

5.9. h) Paying for foreign capacity

It would seem appropriate to pay foreign capacity in the same way as domestic capacity. If foreign capacity participates through an implicit auction or directly through contracts with obligated suppliers, this approach would appear straightforward. If it participates through an explicit auction, financing arrangements would have to be designed to allocate the costs to the suppliers (ultimately consumers) benefitting from the capacity mechanism.

Any penalties paid by foreign capacity providers could be refunded to the suppliers that paid for the capacity.

5.10. i) Appropriately remunerate interconnectors

In a central buyer model where foreign capacity participates directly through an implicit auction, interconnectors could be rewarded with the difference between the zonal (foreign) capacity price and the overall (domestic) capacity clearing price.

In a de-central obligation model, the difference between an implicit auction clearing / average price and a reference price for capacity in the domestic market would need to be paid to the interconnector operators by the beneficiaries of the capacity mechanism.

Additional design questions arise from this since it would be necessary to collect this money from consumers in the capacity mechanism zone and transfer it to the interconnector operators. Alternatively, an explicit auction of entry tickets would allow the interconnector to access revenues directly from the foreign capacity providers, but would create inefficiency in the form of basis risk (as described in section 5.7 of this annex).

Any penalties paid by interconnectors could be refunded to the suppliers that paid for the capacity.

5.11. j) Ensuring compliance with the common rules

Despite existing legislation preventing interference to stop exports at times of scarcity except in specific situations (see section 3.1 of this annex) some fear potential action by Member States or TSOs to limit exports if necessary to prevent local unmet demand. Irrespective of the validity of the argument, this is an issue that would need to be tackled with or without capacity mechanisms. More harmonised, transparent protocols for TSOs and clear rules for Member States to limit their interventions in cross-border flows could avoid this problem along with appropriate sanctions for any infringement, to ensure everyone has confidence that market coupling delivers electricity to higher priced zones.

6. Cross-border participation in other capacity mechanism types

6.1. Cross-border participation in strategic reserves

Unlike other capacity mechanisms that allow beneficiaries of capacity remuneration to continue to compete in the electricity market, if strategic reserves are designed to truly keep their capacity outside the market there may not be the same need to enable explicit cross-border participation.

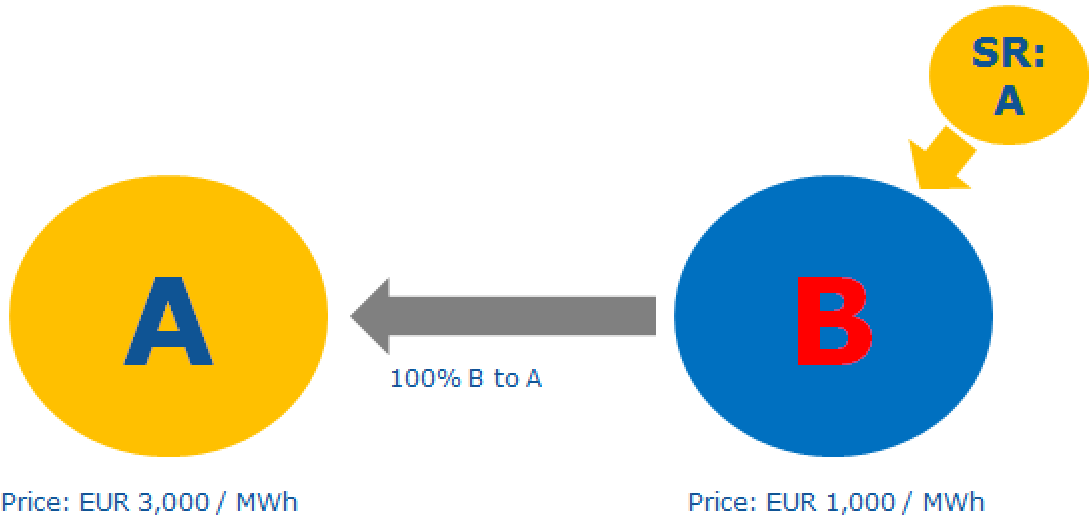
To avoid a distortion to cross-border flows (and the creation of missing money and distortions to investment signals locally and in neighbouring markets) a strategic reserve should in principle only be dispatched once all possibility for the market to deliver has been fully tested and exhausted, the market price cap has been reached because there is still unmet demand, and there is no more potential for imports. To avoid cross-border distortions once intraday markets are coupled, this would mean that a strategic reserve could only be dispatched after gate closure when all possibility for intraday imports had been tested and there was still scarcity. In this situation the use of the reserve should also presumably be priced into the imbalance settlement calculation at the value of lost load to avoid creating missing money.

If a reserve is not designed in this way, however, and does impact on investment signals, for example by acting as a replacement for scarcity prices when dispatched before the market has had a full opportunity to solve a supply shortage and/or at a price that does not reflect the value of lost load, there is a distortion to correct.

Strategic reserve capacity could be procured in a neighbouring bidding zone. However, this would only appear to help security of supply in the zone paying for the reserve in certain circumstances.

Figure A2.3 shows a scarcity event in zone A, which has contracted a strategic reserve in zone B. Zone B either has less scarcity than zone A, or has a lower price cap. The reserve is dispatched because A is experiencing scarcity. However, if the interconnector between A and B was already sending power from B to A, the dispatch of the reserve will make no difference to security of supply in A.

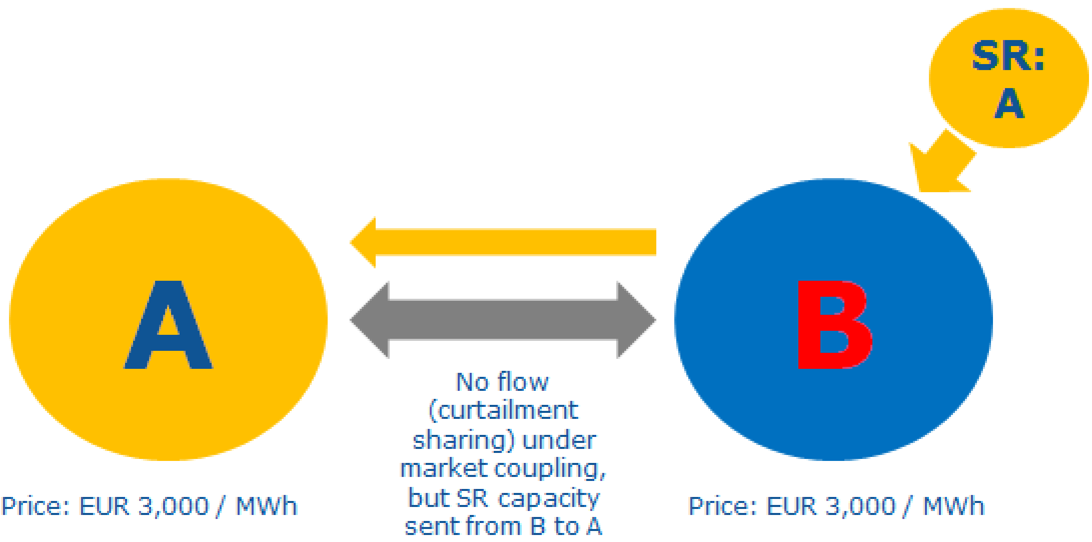
Figure A2.3: Cross-border strategic reserve – no benefit to A



In general, it is to be expected that the dispatch of the strategic reserve would push prices in the market to the price cap, because this should reflect the value of electricity at a time when delivery of the reserve capacity is required (and because if it is dispatched at a lower price it may create missing money in the market where it is located). However, if the dispatch of A's strategic reserve into B would set market prices in B to the price cap in A then the establishment of a cross-border reserve may have to be limited to situations in which two countries share the same price cap.

The dispatch of such a reserve may also need to be limited to situations in which the price caps were reached in both A and B to avoid distortions in B. Similar rules to those proposed in section 5.8 of this annex could however be used to ensure that, in a situation of concurrent scarcity in two Member States which have the same price cap, the power contracted in the reserve could be used to send power from zone B to zone A (see Figure A2.4).

Figure A2.4: Cross-border strategic reserve – forced flow to A



If zone B also had a capacity mechanism, however, any capacity contracted from capacity providers in zone A would presumably also have to be taken into account before interconnector flows were adjusted in favour of A by the dispatch of the strategic reserve.

It therefore appears that the situations in which cross-border reserve capacity could actually be useful to a capacity mechanism zone are limited unless interconnector capacity was reserved specifically to allow the reserve to be dispatched across border. This however would be inefficient because it would permanently reduce the amount of interconnection capacity available commercially for market coupling.

In the future, the design of strategic reserves may adapt, and as energy markets become more regional it would also be possible to design more regional strategic reserves that might overcome the limitations of current designs.

6.2. Cross-border participation in tenders for new capacity

A tender could be opened to cross-border capacity. The sector inquiry found that the 2003 tender in Ireland, and the 2014 tender in Belgium, were both open to foreign capacity providers that were prepared, if successful, to connect permanently to the capacity mechanism bidding zone. In the Irish example, the successful beneficiaries of the tender were located in the Irish bidding zone, and the Belgian tender was abandoned, so there are no examples we are aware of in which a tender for new capacity has actually been used to pay for foreign capacity.

Although opening a tender across borders would remove the immediately distortive impact on locational investment signals of a tender only for domestic capacity, it would not remove the longer term distortive effects of the tender but potentially increase them (since now potentially not only domestic capacity providers but also foreign capacity providers may be prompted to close earlier than otherwise because of competition from a new, efficient competitor subsidised by the tender. These potential impacts of a tender are discussed in more detail in section 6.2.1 of the detailed sector inquiry report.

6.3. Cross-border participation in price based capacity mechanisms

Although in the existing Irish capacity payments scheme, remuneration is available to foreign capacity providers, the mechanism for enabling this (effectively an addition paid for imports and levy on exports) may not be compatible with market coupling since market coupling requires electricity flows to be determined on the basis of electricity prices, not capacity prices. Ireland is in any case adapting its market arrangements, including transitioning from the existing capacity payments model to a new central buyer capacity mechanism.

Given the downsides of a capacity payments approach in which capacity remuneration is set without a competitive process, which are described in section 6.2.4 of the detailed sector inquiry report, and the trend away from these approaches in Europe, the potential for including foreign capacity in these models is not considered further here.

Appendix 2.1: Summary of a possible approach for cross-border participation in central buyer and de-central obligation capacity mechanisms

Design area	Proposal
1) Amount of foreign capacity to include	• For each neighbouring bidding zone, the TSO would calculate the expected average long run amount of imports expected into the capacity mechanism zone at times of scarcity in the capacity mechanism zone.
2) Identifying eligible capacity providers across border	• All potential capacity providers in the neighbouring system would be eligible, except possibly some exceptions if necessary to avoid overcompensation. • Foreign capacity providers would be de-rated in the same way as domestic capacity providers, taking into account their technical long run reliability. • Capacity providers would be able to participate in more than one capacity mechanism to avoid system-wide over procurement.
3) Allocating capacity certificates / contracts to foreign capacity	• Zonal auctions on each border in which foreign capacity providers would offer their capacity and the amount determined in 1) be selected based solely on the EUR / kW price bid. If there is not enough capacity offered below the capacity mechanism zone price then less foreign capacity would be accepted (ie. the maximum price paid for foreign capacity would = the national price). • The foreign capacity would be paid the clearing price. • The interconnector operator would be paid the difference between the zonal clearing price and the capacity price in the capacity mechanism zone – with revenues regulated appropriately. • All cross-border certificates / contracts would be allocated for only one year.
4) Obligations and penalties for foreign capacity providers	• Foreign capacity providers would need to be available in the foreign zone for any period in which there is scarcity in the capacity mechanism zone. They would need to demonstrate their availability by placing a bid in their local market. There would be no (or very limited) exceptions to this obligation (eg. related to maintenance,

	fuel supplies etc). • For any period in which foreign capacity providers are not available, they would pay a penalty, eg. the imbalance price in the capacity mechanism zone. • If a capacity provider has chosen to sell into two capacity mechanisms and there is an hour of concurrent scarcity: ○ If they meet their domestic obligation, unless they *also* make available enough capacity to the market to meet their foreign obligation, they would need to pay a penalty to the foreign capacity mechanism zone. ○ If they fail to meet their domestic and foreign obligations, they would need to pay two penalties – to both the domestic capacity mechanism and to the foreign capacity mechanism zone. • Foreign capacity providers would be tested by the local TSO if they did not deliver during the capacity certificate / contract period to ensure they are actually able to deliver electricity. Fines would apply for failed tests.
5) Obligations and penalties on interconnector operators	• Interconnectors would have an obligation to be operational (technically available) at times of scarcity in either connected zone. • Since interconnector operators will potentially be 'involuntary' participants in each mechanism and would have no direct control over the capacity price they receive (since the price left for interconnection would be determined by the voluntary bids of foreign capacity providers to participate) it would be appropriate to cap the maximum penalties that could be levied on interconnectors for lack of availability.
6) Influencing interconnector flows (without distorting market coupling)	• There would be no possibility for interconnector flows to be influenced by capacity contracts until market coupling price caps are reached. • Rules could be developed to ensure electricity flows in proportion to the cross-border capacity contracts held in an episode of concurrent scarcity where market coupling price caps are reached in two interconnected countries and these price caps do not reflect the value of lost load.

7) Trading of capacity certificates / contracts	• Foreign capacity providers would be able to trade their capacity contracts within the same bidding zone to allow them to manage risks of changing circumstances (for example required maintenance or unplanned outages). • Trading would be limited to other eligible providers that have not already sold all of their de-rated capacity into the relevant capacity mechanism (ie. the mechanism for which the contract is being traded). • A registry is likely to be required to enable this.
8) Financing	• The consumers in the capacity mechanism zone would cover the costs of capacity contracted in that capacity mechanism (including foreign capacity). • Any penalties paid by foreign capacity providers would accrue to the consumers that paid for the capacity.

Appendix 2.2: Pre-requisites to enable the possible approach described in section 5

Requirement	Are harmonised rules a pre-requisite?
National TSO to identify the amount of foreign capacity that contributes on each border	• No, TSOs are already doing this in existing national mechanisms. • Harmonised rules would however be beneficial to avoid overly conservative assumptions and ensure transparency. • In the absence of harmonised rules to determine how this calculation should be made, the methodology used should be scrutinised and agreed by the regulators in the capacity mechanism zone and the neighbouring zone. • In addition, harmonised rules on TSO protocols for dealing with concurrent scarcity situations would help reduce uncertainty (and therefore conservative judgments) related to the establishment of the expected contribution of cross-border capacity.
Identifying eligible cross-border capacity	• No, a declaration could be required that the provider is not in receipt of support designed to remunerate its full investment costs.
De-rating cross-border capacity	• No, but harmonised rules would be helpful to increase the accuracy of de-rating and ensure the way resources are de-rated is consistent and transparent across the EU.
Including cross-border demand response capacity	• Potentially, though it may also be possible in the interim with bilateral arrangements between TSOs (and maybe DSOs). Arranging for appropriate meter data is likely to be challenging. Harmonised rules in this area may be a pre-requisite.
Testing foreign capacity providers	• No, but cooperation with the neighbouring TSO would be required to ensure periodic testing of capacity providers and avoid paying for capacity that can never actually deliver. Harmonised rules may be helpful to make it easier for TSOs to agree on testing requirements and procedures.
Trading of capacity	• No, a registry for trading could be established unilaterally or in cooperation with the neighbouring TSO. A harmonised registry may have advantages in the longer term as more market wide mechanisms are

	introduced but the costs and benefits would need further consideration.

ANNEX 3: REFERENCES

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