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Security of Supply in the Electricity Sector: Analysing Different Capacity Mechanisms and Their Interactions with Demand-side Flexibility Potentials

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Security of supply in the electricity sector: Analysing different capacity mechanisms and their interactions with demand-side flexibility potentials

Results from the joint DIW bridge project "SichER" of the departments Climate Policy and Energy, Transportation, Environment

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Abstract

Germany's energy transition is progressing. Renewable energy sources already cover more than half of Germany's electricity demand. However, as the share of variable wind and solar energy increases, so do the fluctuations in electricity generation. Consequently, flexibility on the supply and demand side of the electricity market is becoming increasingly important. This can be achieved in particular through various types of storage systems and new, flexible consumers as part of sector coupling.

Various policy options for security of supply in the electricity system. Since at least the energy crisis of 2022, there has been a growing debate in Germany on whether additional policy instruments are needed to ensure security of supply in the electricity system as the energy transition progresses. In this context, various forms of capacity mechanisms are being discussed, including, in particular, centralised and decentralised capacity markets and mandatory hedging on futures markets. Another option is a refined reliability reserve.

Challenges for all capacity mechanisms currently under discussion. The centralised and decentralised capacity mechanisms currently under discussion face challenges and some unresolved issues. While centralised capacity markets can provide investment security for power plant capacity, they carry the risk of long-term market distortions and cost increases resulting from an oversized power plant fleet. The effectiveness of long-term hedging and the capacity of decentralised mechanisms to provide long-term investment security have also been subject to scrutiny.

The electricity system needs flexibility. Given that the future electricity system will be largely based on variable solar and wind energy sources, it will require flexible suppliers and consumers. Without sufficient flexibility, the energy transition would be unnecessarily challenging and costly. With the expansion of wind and solar energy, low-cost energy will be available during many hours in the future. This, in combination with storage and other flexibility options, can help to meet the energy demand of other hours when the supply of renewable energy is lower.

Capacity mechanisms should incentivise flexible demand. An essential criterion for the design of a capacity mechanism is the extent to which it offers sufficient incentives for decentralised demand flexibility. However, there is a risk that the necessary revenues for flexible demand in the electricity market cannot be realised in a capacity market, which may impede the expansion of flexibility. Consequently, it is vital to ensure that the portfolio of various flexibility options has a level playing fieldand that barriers to investment in flexibility are avoided when designing a capacity mechanism.

Advantages of a reliability reserve. A qualitative analysis indicates that the development of the capacity reserve into a reliability reserve with a moderately high trigger price can be advantageous in many respects when compared to the other mechanisms under current discussion. In particular, this approach provides more effective incentives for the utilisation of flexibility technologies. This is illustrated by means of quantitative model calculations based on an open-source electricity sector model developed by the German Institute for Economic Research (DIW Berlin). The model indicates that a centralised capacity market in 2030 would unlock less than half the demand-side flexibility of a reliability reserve. This aspect has received too little attention in the energy policy debate to date and should be considered when developing the design of future capacity mechanisms. There is considerable evidence that a further development of the existing capacity reserve into a reliability reserve is more aligned with the energy policy goals than the capacity mechanisms that have been predominantly discussed thus far. This is particularly relevant in the context of the necessary development of flexible demand.

1 Background and objective

Energy transition with fluctuating renewable energies. Germany is making progress towards a transition to renewable energies.[1] In 2023, renewable energy sources provided almost 52% of German electricity demand (Umweltbundesamt 2024), with electricity generation from renewable energies continued to rise in the first half of 2024 (AGEE-Stat 2024). Nevertheless, the increasing contribution of wind and solar energy to electricity generation is leading to greater fluctuations in electricity production (López Prol and Schill 2021). This results in an increased number of hours during which the potential electricity production from renewable energies exceeds demand. At the same time, there will still be many hours in the foreseeable future when wind power and solar energy alone cannot meet demand.

Growing role of flexibility options. The flexibility of the electricity system is becoming an increasingly crucial factor in addressing the variability of wind and solar energy as well as in maintaining equilibrium between supply and demand (Kondziella and Bruckner 2016). There is potential for flexibility on both the generation and demand sides, as well as related to various types of energy storage and through large-scale electricity exchange. Examples of such utilisation include flexible power plants, load shifting in industry and households, electricity and heat storage technologies, and European cross-border electricity trading (Lund et al. 2015; Schill 2020; Roth and Schill 2023).

Advantages of demand-side flexibility. The relevance of demand-side flexibility in this context is significant, as it enables the shifting of energy consumption from periods of low renewable electricity generation to periods of high generation. This not only reduces electricity costs for consumers but also benefits the system as a whole: It reduces the need for conventional power generation during periods of low renewable energy feed-in. Other advantages of demand-side flexibility include improved integration of renewable energies with a corresponding reduction in CO_2 emissions (Golmohamadi 2022) and a reduction in the need to expand the grid infrastructure (Kim and Shcherbakova 2011). Compared to many storage technologies, demand flexibility is also often more energy efficient and economically more cost-effective, as there is usually

[1] DIW Berlin's Ampel-Monitor Energiewende regularly compares the current status of the energy transition with the German government's targets for selected indicators from the areas of renewable energies and sector coupling: https://www.diw.de/ampel-monitor. See also Schill et al. (2024).

no additional conversion of electricity into an intermediate product, but rather a temporal shift in electricity utilisation (Finn et al. 2011).

Capacity mechanisms and missing money. Irrespective of the aforementioned flexibility options, so-called capacity mechanisms have long been discussed in liberalised electricity markets.[2] For decades, energy economists have been discussing whether and in what form capacity mechanisms are necessary in conventional electricity markets with dispatchable electricity generation. The provision of sufficient capacity in energy-only markets (EOM) therefore appears questionable, as large parts of the demand for electricity do not react sufficiently strongly to price signals in real time and efficient pricing is not possible in the event of supply scarcity (Cramton et al. 2013). Maximum prices in the electricity market must therefore be set by regulators. It does not seem plausible - and not just since the experiences of the 2022 energy crisis - that regulators would tolerate very high prices for a long period of time. However, setting price caps in the electricity market that are too low can cause a so-called "missing money" problem, particularly for peak-load power plants (Box 1). This can lead to insufficient dispatchable capacity being held in the electricity market and security of supply falling to an undesirably low level. Capacity mechanisms are intended to address this problem. They are intended to remunerate operators of power plants, storage facilities or demand flexibility for the capacity they maintain, which should ultimately serve to ensure security of supply.

Capacity mechanisms and transformation. Most recently, capacity mechanisms have been discussed primarily in the context of the energy transition, i.e. in connection with an accelerated transformation of the electricity system toward variable renewable energy sources. In Germany, as in many other countries, renewable energies are being expanded rapidly and supported by various political support measures to reduce greenhouse gas emissions from the electricity sector and thus achieve the climate targets. The politically intended, accelerated phase-out of coal is also relevant in this context. At the same time, sector coupling, i.e. new electricity consumers such as electric cars, heat pumps and electrolysers, is leading to disruptive changes in the electricity market on the demand side. This transformation can create additional uncertainties about future revenues on the electricity market.

[2] In Germany, the electricity market was liberalized with the revision of the Energy Industry Act in 1998. Previously, there were regional monopolies with integrated suppliers. These had an incentive to maintain high power plant capacities due to cost-based regulation. This incentive was removed after liberalization.

Box 1: "Missing money" and "missing markets"
In liberalised electricity markets, in which demand and supply determine the price on the wholesale market, "missing money" is often postulated (Cramton et al. 2013). If additional power plants are needed to cover peak load, they may only be used in a few hours and perhaps only in a few years. During these hours, market prices would have to rise very sharply ("scarcity prices") in order to cover both the variable costs and the investment costs of these power plants. For investors, the question therefore arises as to whether the regulatory authorities might prevent such price peaks in order to protect customers from high electricity costs, which would, however, jeopardise the profitability of the power plant. This inherent uncertainty increases investment risks for power plant operators and reduces the willingness of private investors to invest in these technologies to a sufficient extent from a security of supply perspective. The problem of "missing money" can also arise if system services such as black start capability or certain flexibility characteristics of electricity producers or consumers are not priced correctly. In addition, the problem of "missing markets" has also been discussed recently. This arises when markets to hedge against future market risks are incomplete or even completely absent (Newbery 2016).

The question therefore arises as to whether and how security of supply must and can be safeguarded by additional policy instruments, particularly during the transformation period. At the same time, a future electricity system with a portfolio of different flexibility options also offers the prospect of greater demand elasticity, i.e. a stronger reaction of demand to price changes. This could - in the longer term - lead to more stable electricity prices with fewer extreme price peaks. Against this backdrop, a solution that is particularly suited to the upcoming transformation phase is sought. In this context, a wide range of different capacity mechanisms are currently being discussed in Germany (Chapter 2 & Chapter 3).

Interaction between capacity mechanisms and flexibility options. The interaction between capacity mechanisms and flexibility, particularly on the demand side, has received little attention so far. Most flexibility options can only be utilised effectively if the benefits they bring to the overall system are adequately reflected in their market revenues. However, there is a conflict of objectives and interests: Traditionally, capacity mechanisms have primarily supported power plants. Their promotion to ensure security of supply can hinder investments in other flexibilities, in particular flexible demand (chapter 4).

Subject of this study. The following questions therefore arise: How do different capacity mechanisms interact with flexibility options in the electricity market? How can security of supply in the electricity market be guaranteed while at the same time unlocking flexibility potential on the demand side? In particular, how can demand-side flexibility be prevented from being disadvantaged, resulting in inefficiently high provision and utilisation of gas-fired power plants? These questions are relevant in terms of energy, climate and industrial policy. This joint consideration of security of supply and flexibility has so far been neglected in the debate.

Structure of this study. To answer these questions, the current status of the security of supply debate in Germany is presented first. Different types of capacity mechanisms are then described and discussed regarding key design parameters and challenges. Based on this, a qualitative analysis is made of whether and how these capacity mechanisms can tap flexibility potential. In order to illustrate the resulting statements quantitatively, an open-source electricity sector model is used to analyse the effect of two central mechanisms on the expansion of demand-side flexibility technologies.

2 Capacity mechanisms in Germany: current status and options under discussion

2.1 Current status in Germany

Energy-only market. At present, the German electricity market is essentially an energy-only market. This means that electricity volumes (megawatt hours, MWh) are primarily traded, but there is no defined demand and no structured payments for generation capacity or other dispatchable capacity (MW). Such a market is often referred to as an "energy-only market" (EOM). In fact, however, there are hardly any energy-only markets in their pure form, as futures markets, among others, already implicitly contain a certain capacity elements. The balancing power market can also be regarded in part as a capacity mechanism.

"Energy-only market 2.0" with a capacity reserve. The current form of the German electricity market is also referred to as "EOM 2.0" by the Federal Ministry for Economic Affairs and Climate Protection (BMWK). This term was introduced in the 2015 White Paper, "An electricity market for the energy transition" (BMWi 2015), and is also used in current ministry documents (e.g. BMWK 2024). In EOM 2.0, the electricity market is secured by a so-called capacity reserve (see Neuhoff et al. 2013). This reserve came into force for the first time in 2020 on the basis of the Capacity Reserve Ordinance[3] issued in 2019. Under the capacity reserve, power plants are kept outside of the other electricity market and are only used in defined exceptional situations. Their volume is determined by the Federal Network Agency (Bundesnetzagentur) for provision periods of two years. To date, the target reserve capacity has always been 2 gigawatts (GW).[4] This capacity is then procured by the transmission system operators by auction.[5] However, the target of 2 GW has never been reached to date. In the first two provision periods 1.10.2020-30.09.2022 and 1.10.2022-30.09.2024, only just under 1.1 GW was successfully awarded in each case; in the current, third provision period 1.10.2024-30.09.2026, the figure is 1.2 GW. The majority of these are gas-fired power plants, some of which were built in the early 1970s.[6] The costs of maintaining

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[3] Capacity Reserve Ordinance - KapResV: https://www.gesetze-im-internet.de/kapresv/

[4] Further information on this can be found on the homepage of the Federal Network Agency: https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Versorgungssicherheit/KapRes/start.html

[5] Information on the campaigns can be found on the Netztransparenz homepage: https://www.netztransparenz.de/de-de/Systemdienstleistungen/Betriebsfuehrung/Kapazit%C3%A4tsreserve

[6] Power plant list of the Federal Network Agency, as of 15 April 2024 https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Sachgebiete/Energie/Unternehmen_Institutionen/Versorgungssicherheit/Erzeugungskapazitaeten/Kraftwerksliste/Kraftwerksliste.xlsx

and using these power plants are passed on to all electricity customers. As of November 2024, this reserve has never been activated.

Grid reserve. In addition to this capacity reserve, there is the so-called grid reserve. The grid reserve includes power plants that can no longer be financed on the electricity market but whose generation capacity is still required to avoid bottlenecks in the transmission grid.[7] These so-called redispatch measures serve to stabilise the grid and are necessary if domestic grid bottlenecks occur that are not structurally taken into account in the wholesale market. The power plants in the grid reserve may only be used for redispatch measures. The volume of capacity to be held in reserve for this purpose rose from 3.6 GW in winter 2014/15 to 10.2 GW for winter 2025/26 and recently fell again slightly to 9.2 GW for winter 2026/27.

Security reserve. In addition to the capacity reserve and grid reserve, another reserve was introduced in Germany in 2016, the so-called security reserve.[8] This is essentially an accompanying instrument for the coal phase-out. Between 2016 and 2019, a total of eight lignite-fired power plant units were transferred from regular operation to the security reserve in several steps. The power plant operators committed to keep the units operational for a period of four years respectively. In return, they received a payment that was prorated to all electricity consumers via the grid fees. During the peak of the electricity price crisis in 2022 (cf. Kittel et al. 2022), five of these lignite-fired units were reactivated when the outage of a large number of French nuclear power plants threatened an electricity shortage (Federal Government 2023). However, the final decommissioning of these power plant units at the end of March 2024 marked the end of the security reserve.

Distinction between capacity reserve and grid reserve depending on electricity price zones. Ultimately, the distinction between the capacity reserve on the one hand and the grid reserve on the other is a question of the definition of the electricity price region. To date, there has been a uniform electricity price zone in Germany. If the generation capacity within a defined electricity price zone, including import capacities, is not sufficient to cover the demand within this zone, the capacity reserve is maintained. The same applies in principle to the security

[7] Further information on this can be found on the homepage of the Federal Network Agency: https://www.bundesnetzagentur.de/DE/Fachthemen/ElektrizitaetundGas/Versorgungssicherheit/Netzreserve/start.html

[8] Further information on security readiness can be found on the homepage of the Federal Network Agency: https://www.bundesnetzagentur.de/DE/Beschlusskammern/BK08/BK8_07_Kraftwerksth/73_Sicherhbereits/BK8_Braunkohlestilleg.html

reserve. In the event that the transmission capacities of the electricity grid within an electricity price zone are not sufficient to cover the demand in the electricity price zone with the existing generation capacity, the grid reserve is maintained. If the electricity price zones were smaller, the power plants in the grid reserve would no longer be required for congestion management and could therefore either be transferred to the market or to the capacity reserve.

New pricing zones would require reform of reserves. There has long been a debate as to whether the standardised electricity price zone in Germany should be split up or whether there should even be a switch to local markets or nodal prices. In this case, some or even all of the power plants in the existing grid reserve would be transferred to the capacity reserve. Without a reform of the existing capacity reserve, these would only be used in the event of extremely high prices of more than EUR 3000/MWh on the day-ahead market or even higher prices on the intraday market, which arise when supply on the electricity market cannot meet demand in the respective region. A further development of the capacity reserve into a reliability reserve with a moderately high trigger price could prevent extremely high electricity market prices from occurring at times.

2.2 Power plant strategy and Power Plant Safety Act

Power plant strategy. The BMWK had already announced that it would develop a power plant strategy for dispatchable, emission-free power plants in the first half of 2023.[9] After several stages of discussion and revision, the Federal Government agreed on a power plant strategy in July 2024.[10]

Power Plant Safety Act and three "pillars." The power plant strategy (Kraftwerksstrategie) is now to be implemented in the form of a Power Plant Safety Act (Kraftwerkssicherheitsgesetz), which is currently in the consultation process.[11] This law regulates the first two of three planned "pillars" for new power plants.[12] Initially, a total of 13 GW of dispatchable generation capacity is

[9] BMWK press release dated 1 February 2023: https://www.bmwk.de/Redaktion/DE/Pressemitteilungen/2023/02/20230201-sichere-versorgung-mit-strom-bis-ende-des-jahrzehnts-gewahrleistet.html

[10] https://www.bmwk.de/Redaktion/DE/Pressemitteilungen/2024/07/20240705-klimaneutrale-stromerzeugung-kraftwerkssicherheitsgesetz.html

[11] https://www.bmwk.de/Redaktion/DE/Meldung/2024/20240911-kraftwerkssicherheitsgesetz.html

[12] https://www.bmwk.de/Redaktion/DE/Downloads/Energie/kraftwerkssicherheitsgesetz-wasserstofffaehige-gaskraftwerke.pdf

to be put out to tender. A comprehensive capacity mechanism is to be added from 2028 as a third pillar.

First pillar. In the first pillar, new hydrogen-capable ("H2-ready") gas-fired power plants with a capacity of five gigawatts are to be put out to tender "promptly," supplemented by two gigawatts of modernisation work to make existing gas-fired power plants "H2-ready." These must switch their fuel supply to blue or green hydrogen from the eighth year of commissioning or modernisation at the latest. In addition, 0.5 gigawatts of capacity for pure hydrogen power plants ("hydrogen sprinters") and 0.5 gigawatts of long-term hydrogen storage are to be put out to tender. The funding of these power plants constitutes state aid that must be notified to the EU Commission. The German government plans to notify this first pillar as a decarbonisation measure within the meaning of the Climate, Environmental and Energy Aid Guidelines.

Second pillar. The second pillar consists of a further five gigawatts of gas-fired power plants, which are primarily intended to contribute to security of supply. In contrast to the first pillar, the subsidisation of these power plants is to be notified to the EU Commission as a security of supply measure under state aid law.

Third pillar. The third pillar is a comprehensive capacity mechanism that is open to all technologies. It is to be operational from 2028. The output of the power plants tendered in the first two pillars is to be taken into account. Double subsidies are to be ruled out.

2.3 The German government's current proposal for a comprehensive capacity mechanism

Options paper. The Federal Government has discussed the question of what form the capacity mechanism (third pillar) should take with a large number of stakeholders, including as part of the Climate Neutral Electricity System Platform. In July 2024, the BMWK presented an options paper on the future design of the electricity market, which includes four types of capacity mechanisms (BMWK 2024). Both dispatchable power plants and technologies for flexibilizing demand are to be considered. The options paper was put out for consultation and commented on extensively by various stakeholders (dena 2024).

First option: mandatory peak price hedging. The first of the four options is a capacity hedging mechanism through peak hedging, in which electricity suppliers are obliged to hedge their electricity sales on futures markets against price peaks. This would expand the current futures trading, in which products are currently traded that guarantee a fixed price for the supply of a constant quantity of electricity over a longer period of time. The obligation to extend "hedging" is intended to incentivise demand for peak price products. These could be provided by dispatchable capacities, for example, which in turn could generate additional revenue and corresponding investment incentives.

Second option: decentralised capacity market. The second proposed option is a decentralised capacity market (DCM). In this concept, electricity suppliers are made responsible for securing their electricity deliveries with dispatchable capacities. This can be done either by reducing the peak load of the customers they supply or by purchasing capacity certificates. The capacity certificates are provided after certification by a central body, for example by power plants, storage facilities or flexible loads, and are tradable. For the operators of flexible capacity, additional revenue opportunities and, thus, investment incentives arise from the sale of certificates on the market.

Third option: centralised capacity market. The third option proposed is a centralised capacity market (CCM). Here, a central body, e.g. the transmission system operators or the Federal Network Agency, would determine the necessary capacity requirements in advance and procure them in auctions. The capacities awarded in the auctions would receive a regular cash flow in the long term, which would provide a particularly high level of investment security for these capacities.

Fourth option: combined capacity market. The fourth option, currently favoured by the German government, combines elements from the centralised and decentralised capacity market in what is known as a combined capacity market (CCM). This is based in part on a proposal by the Monopolies Commission (2023). Dispatchable capacities with a long-term investment horizon are put out to tender centrally. In addition, a decentralised capacity market segment will be created in which electricity suppliers will have to cover their peak load with certificates. The intention is that the certificates in this segment will tend to come from existing plants, storage facilities or demand-side flexibility with a shorter investment horizon.

Supplemented by a reserve. In addition to the four variants of capacity mechanisms outlined above, the options paper considers a reserve from existing plants to be useful. Similar to the current capacity reserve (see section 2.1), it should provide secured capacity for unforeseeable situations. The "triple crisis" from 2022 is cited as an example of this, in which Russian gas supplies were cancelled, French nuclear power plants were out of operation and the operation of hydropower and the cooling of coal power was restricted by Europe-wide droughts. Such extreme cases could be covered by a reserve. A strategy for the further development of the reserve as an independent capacity mechanism is not developed in the options paper. However, it is a central component of the analysis presented here.

3 Overview of different capacity mechanisms to safeguard security of supply

There is already practical experience with various types of capacity mechanisms in the European Union and other countries. These include the centralised and decentralised capacity markets currently being discussed in Germany as well as capacity reserves, which are also known as strategic reserves or reliability reserves. In addition, various options for mandatory hedging of market participants on futures markets are being discussed (Figure 1). Capacity markets are usually organised centrally. Only in France is there a decentralised capacity mechanism (ACER 2023a).

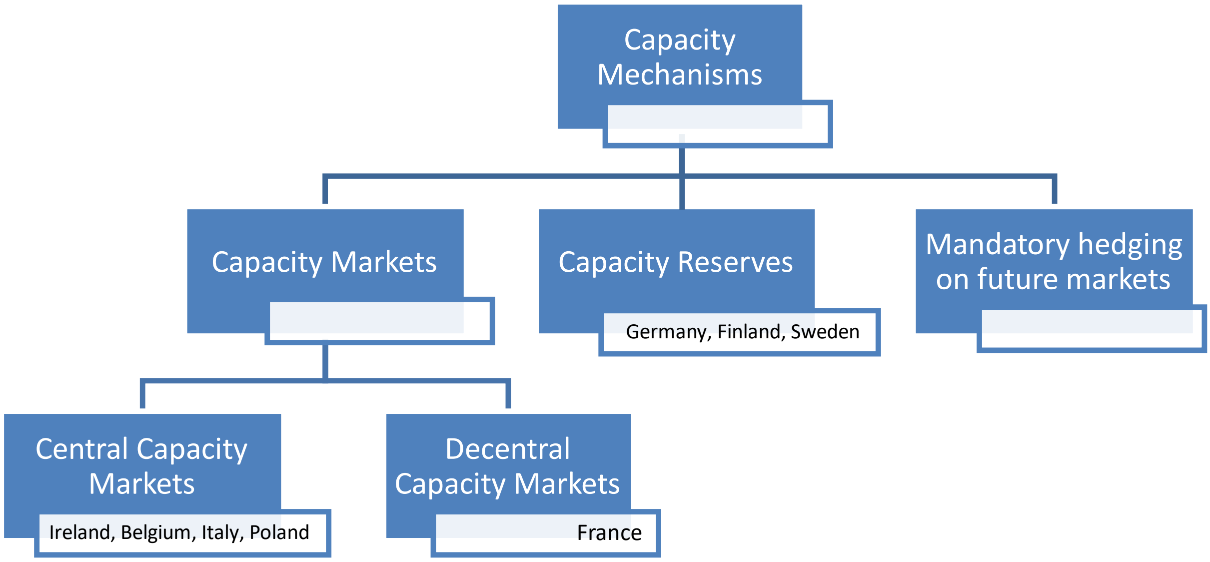

Figure 1: Overview of different types of capacity mechanisms

3.1 Central capacity market

3.1.1 Key features and design parameters

Capacity is defined and procured centrally. In the centralised capacity market, a central player, usually the regulatory authority, determines the demand for dispatchable capacity to be provided in the electricity system. The volume determined in this way is then put out to tender in auctions in which both existing and new capacity to be built can participate. The players offering secured capacity at the lowest price are awarded a contract in the form of capacity payments. These market participants continue to market their electricity generation on the wholesale market, but also receive payments from the capacity market. The costs for the capacity payments are generally passed on to electricity customers.

Long-term investment security. Dispatchable capacity is generally put out to tender with a lead time of several years. This means that power plants that still have to be built after being awarded a contract in the capacity market can also participate. A long-term contract for the capacity payments creates a high level of investment security. A centralised capacity mechanism can thus ensure that sufficient generation capacity is made available for critical situations in the system through long-term tendering in combination with suitable pre-qualification requirements and penalties.

Incentive for the use of capacity in critical hours. The consideration for the capacity payments is the contribution to security of supply. However, the mere provision of capacity is not sufficient for this. It must also be ensured that electricity is actually generated or demand is reduced during peak load hours and that no market power is exercised during such hours (Cramton et al. 2013). To this end, power plants can be penalised if they do not produce during hours of critical security of supply (Mastropietro et al. 2016). These penalties must be set high enough to ensure that gas-fired power plants, for example, have sufficient gas supply contracts or reserves. As an alternative to penalties, players who benefit from capacity payments can be obliged to sign call options (Cramton et al. 2013; Bhagwat and Meeus 2019). Thus, in the event of high electricity prices, they are obliged to repay the spot market price less the trigger price of the option. If these repayments are passed on to electricity customers, they can be protected against price peaks above the strike price with these instruments, also known as "reliability options" or "security of supply contracts" (Elberg et al. 2012).

3.1.2 Challenges and points for discussion

Risk of oversizing. One point of criticism often brought forward about centralised capacity markets is that regulatory authorities oversize the capacity market due to a preference for risk avoidance. Reasons for this include underestimating the contribution of possible imports or applying too high safety margins for individual power plant capacities. Political economy aspects can also lead to a tendency for capacity markets to be oversized and thus cause excessive costs: in case of doubt, those politically responsible for a capacity market will prefer to order slightly more capacity than is optimally required to protect themselves against a possible failure of the instrument. Oversized capacity markets are associated with excessive costs, which ultimately must be borne by electricity consumers.

Distortions due to the regulatory definition of capacity. Another challenge with capacity markets lies in the definition of the product of dispatchable capacity. The product definition means that the mechanisms are no longer technologically neutral; instead, the regulatory design influences the relative competitiveness of different technologies. Overly strict qualification requirements, which in practice are often tailored to conventional power plants, can exclude small-scale and decentralised flexibility options in particular from the capacity market. For storage systems, the question arises as to whether and to what extent their performance should be "de-rated" in order to take account of their limited deployment periods due to the energy storage capacity (Fraunholz et al. 2021). If flexibilities other than dispatchable power plants are structurally disadvantaged by the product definition of the capacity market, this not only has the direct effect that these technologies do not get a chance on the capacity market, but also the indirect effect that they are exposed to increased competition from subsidised power plants during operation. What this means for demand-side flexibility is discussed in chapter 4 in more detail.

Limited adaptability. Centralised capacity markets are designed to offer long-term investment security for dispatchable capacities, usually power plants. However, this comes at the price of limited adaptability to new technological and market developments.

Protection for electricity customers as a challenge. As mentioned above, either penalties or reliability options can be used to incentivise the plants subsidised via the capacity market to actually be in operation during hours of scarcity. In the case of penalties for non-operation, however, the question arises as to the amount of the penalty. If it is set too low, it may not be effective, e.g. in times of high fuel prices. On the other hand, a penalty payment that is too high can lead to excessive financial risks in the event of a plant failure, which in extreme cases can lead to bankruptcy instead of the delivery of a promised service. Furthermore, this approach would protect electricity producers against low electricity prices without providing electricity customers with financial protection against high electricity prices in return. If a reliability option is used as an alternative, the hedging of electricity trading via futures markets becomes more complex and limited, as electricity producers will not commit to repayment of spot prices in a futures product in addition to a reliability option. They would therefore have to use additional option contracts to complement the reliability option. If they are unwilling or unable to take on this complexity, there is a risk that electricity customers will only be protected above the often very high target trigger prices (e.g. in the amount of the variable generation costs of hydrogen power plants) and not for electricity price increases up to this level.

3.2 Decentralised capacity market

3.2.1 Key features and design parameters

Electricity suppliers responsible for security of supply. In contrast to the centrally organised capacity market, the decentralised capacity market transfers responsibility for security of supply to the market players: The electricity suppliers must prove ex-post that not only sufficient energy, but also sufficient capacity was available at all times to supply their customers. This can be achieved in part through their own provision (e.g. reduction of peak loads for the customers supplied) and via a separate capacity market on which capacity certificates are traded. Power plant operators and other providers of dispatchable capacity can first have their capacity certified and then sell it to electricity suppliers.

Openness to technology and innovation. A decentralised capacity market should ensure security of supply in a way that is particularly open to technology and innovation, as suppliers have more options available to them than in a centralised capacity market. This includes options for load flexibilization for the respective customers through storage and other flexibilities, the pre-qualification of which would be a challenge in a centralised capacity market.

3.2.2 Challenges and discussion points

Regulatory definition of capacity. A decentralised capacity market also requires a clear regulatory definition of the product of dispatchable capacity and is subject to similar challenges as a centralised capacity market in this respect. This also includes certain prequalification requirements and de-rating factors.

Control effort for central actor. The decentralised capacity market also requires a central actor who must continuously monitor and ensure compliance with the requirements for the allocation of capacity certificates. The same applies to compliance with the requirements for capacity provision. In addition, penalties for non-compliance must be set and, if necessary, collected. These tasks could be performed by a regulatory authority, for example. In contrast to a centralised capacity market, however, the regulatory authority does not have to decide centrally to what extent dispatchable capacity is to be reserved for the coming years.

Time horizon. At the end of each year, supply companies must prove that they have acquired sufficient capacity certificates to cover peak demands of the previous year. The decentralised capacity mechanism is therefore retrospective rather than forward-looking. It also seems plausible that capacity certificates are only liquidly traded for relatively short time horizons. No supply company can predict the electricity demand of its customer base for several years in advance, as electricity customers can generally switch suppliers in a competitive electricity system. This increases the uncertainty of the decentralised forecast compared to a centralised forecast and there is no corresponding predictability for investors in dispatchable loads and flexibility.

Political risk. The decentralised capacity market also holds a political risk for market participants: there are many opportunities for regulatory authorities to adjust the rules and justify this adjustment. Examples of this include an increase in supply in the capacity market by adjusting the de-rating factors, i.e. an increase in the nominal capacity contribution of a power plant type, or a reduction in the demand for certificates. The latter could be achieved, for example, by changing the definition of the reference period in which the demand for electricity is measured in order to determine how many capacity certificates must be held. The regulatory authority could thereby change the scarcity, and thus, the pricing in the short term. It is therefore questionable whether a decentralised capacity market can provide sufficiently credible incentives for investments in long-life generation or storage facilities. This could, as expected, lead to risk premiums and correspondingly higher costs for market players or, in extreme cases, even to an undesirably low level of investment activity. This is probably one of the reasons why there are only a few decentralised capacity markets in practice, with France being a notable exception. There, however, the company Électricité de France (EDF) dominates the market and is protected against regulatory uncertainties by its state ownership. In this context, it is interesting to note that the European Commission has only approved the implementation of the decentralised capacity market in France in combination with public tenders with multi-year products for new capacities.[13] France was apparently unable to demonstrate that its decentralised capacity mechanism would support such investments.

Limited protection of the demand side against high prices. The experience of the recent energy crisis in France shows that not only electricity producers but also electricity customers suffer from volatile electricity prices. In the decentralised capacity market, electricity customers or their suppliers would have to hedge with forward products for both energy and capacity

[13] Homepage of the European Commission: https://ec.europa.eu/commission/presscorner/api/files/document/print/en/ip_16_3620/IP_16_3620_EN.pdf

market certificates in order to cushion such fluctuations in electricity costs. The parallel trading of capacity certificates and forward products on the electricity market increases complexity and therefore tends to reduce hedging with forward products. Thus, as a result, it can tend to increase fluctuations in electricity costs compared to the current energy market instead of helping to mitigate them.

Regionalisation as a challenge. Another challenge of the decentralised capacity mechanism is regionalisation. If capacity certificates are traded on a national or even Europe-wide basis, this would implicitly presuppose the existence of a congestion-free electricity grid ("copper plate"). Taking grid congestion into account in the decentralised capacity market, on the other hand, would require separate capacity requirements to be defined and capacity markets to be established for small regions. The smaller these regions are, the higher the risk of low liquidity and market power. The establishment of a transfer mechanism for capacity certificates between regions and countries appears possible but is likely to be complex and politically controversial in terms of its concrete design, as well as subject to major regulatory uncertainties regarding future adjustments.

3.3 Reliability reserve

3.3.1 Key features and design parameters

Centrally procured and managed reserve. In oil and gas markets, it has long been common practice to ensure security of supply through state-managed or ordered reserve stocks. This concept has also been transferred to electricity markets, where it is referred to as strategic reserve, capacity reserve or reliability reserve (see also Chapter 2.1). In such a reserve, capacity from dispatchable power plants is held in reserve, which only produces electricity in predefined extreme situations, for example if the electricity price exceeds a predefined threshold, the trigger price. A central regulator determines the required size of the reserve and the technical prequalification features and procures the capacities in auctions. The costs and revenues of the reserve are passed on to all electricity customers.

Reserve outside the electricity market. In contrast to centralised or decentralised capacity markets, the dispatchable capacities in the reliability reserve do not participate in the normal wholesale market for electricity. This means that they do not have a direct impact on pricing on the electricity market at times when the wholesale price is below the trigger price.

Fast implementation and low administrative effort. In principle, the reliability reserve has the advantage over capacity markets that it can be implemented quickly. It is also associated with low administrative costs compared to the centralised and decentralised capacity market. In particular, it can build on existing reserve capacities and established processes for their procurement and management (cf. chapter 2.1).

Strengthening short-term and futures markets. A reliability reserve can strengthen short-term markets by creating sufficient supply so that there is a market equilibrium and functional pricing at all times. This is also an important basis for functioning futures markets and can promote hedging with various futures products by avoiding the risk of a trading partner defaulting or the need to provide high security deposits. By avoiding extreme price peaks, a reliability reserve also avoids the so-called margin calls that escalate in such situations: participants in the futures market must deposit money with the trading houses for possible contract defaults. The Credit Institute for Reconstruction (KfW) had to provide liquidity assistance for this during the energy crisis, estimated at a total volume of €100 billion (BMWK 2022). A reliability reserve avoids the risk of extremely high prices and the associated government hedging requirements. This strengthens the energy market and avoids the risk of the state being left with high costs in the event of liquidity assistance or similar.

3.3.2 Challenges and discussion points

Macroeconomic and social dimension of the trigger price. An important design parameter in the implementation of the reliability reserve is the determination of the trigger price. The trigger price must be low enough to avoid social and economic distortions. In Germany, for example, the security reserve was only intended to be used if supply on the electricity market did not cover demand, i.e. at prices between 3,000 and 20,000 euros/MWh. When the power plants from the security reserve were needed to ensure security of supply in the winter of 2022, this trigger price would have caused electricity prices and thus ultimately the costs for consumers to rise to a correspondingly high price level. To prevent this, the rules were adjusted at short notice - all power plants on standby were able to sell their generation on the electricity market at marginal costs (BNetzA 2022). However, this means that the concept of a reserve that is only used when supply does not cover demand on the market no longer appears credible.

Trigger price must enable investments in the electricity market. At the same time, the trigger price must be high enough so that market participants in the electricity market can utilise all generation capacities and flexibility options and generate sufficient revenue to refinance investment costs and annual fixed costs. This is necessary for existing, but especially for new investments in the market.

The trigger price must be both low and high enough. If both conditions can be met at the same time, the investment environment is strengthened and investors in the energy market can be confident that there is no threat of regulatory changes in crisis situations and that they can refinance their investments through high prices (up to the trigger price).

Regulatory credibility. For the balance between regulatory credibility and sufficient incentives for investments in the market, a trigger price of around EUR 500/MWh seems plausible from today's perspective. Consideration could also be given to reducing the trigger price if the reserve is triggered for a longer period at a time, for example for a week. Similar rules are common for price caps in many electricity markets. It is crucial for investment activities in the regular electricity market that the rules for using the reserve are credible and that all market participants assume that they will be adhered to. The EU offers the advantage here that all corresponding regulations cannot be implemented by member states alone, but also require European approval. All member states have spoken out in favour of this to avoid distortions and restrictions on the European electricity market. In the context of a reliability reserve, this limits the risk of individual countries - including the German government and the Federal Network Agency - adapting the regulations at short notice. This strengthens the credibility of the entire reliability reserve for investors.

European coordination desirable. European coordination would be desirable for the procurement and activation of a capacity reserve so that neighbouring countries can support each other with their respective reliability reserves (Neuhoff et al. 2016). However, this also applies in principle to other capacity mechanisms.

3.4 Mandatory hedging on futures markets

3.4.1 Key features and design parameters

Risk management by market participants desirable. Strengthening risk management for all electricity customers and their suppliers is fundamentally desirable, regardless of the discussion about capacity mechanisms. This can help to reduce the volatility of both electricity costs for customers and revenues for producers and flexibility providers.

Hedging obligation for suppliers. However, voluntary risk management does not necessarily lead to sufficient capacity being maintained to ensure security of supply in exceptional situations. For this reason, an obligation is being discussed for suppliers to hedge the electricity they supply for a certain period of time in advance and to gradually increase the proportion of hedged electricity (Connect Energy Economics 2024; Grimm and Ockenfels 2024). Suppliers could increasingly buy forward, future, and option products for electricity. The hedging obligation would have to significantly exceed the hedging that has been customary in risk management to date and is already prescribed by the EU and be further developed so that the additional demand actually leads to investments in controllable services and flexibility.

3.4.2 Challenges and discussion points

Mandatory hedging requires controls. A high level of additional hedging over and above risk management is not in the electricity suppliers' own interests, as this increases the prices for hedging products on the one hand and reduces scarcity and therefore prices on the spot market on the other. The hedging obligation must therefore be strictly controlled. This appears to be a major challenge, as a supplier's electricity requirements can change significantly in the long term due to customer changes and therefore cannot be reliably estimated. In addition, a large number of bilateral contracts are possible with which a supplier can increase or reduce its hedging. Their overall effect is difficult to estimate.

Implementation of the hedging obligation is very complex. It is not clear how the mandatory hedging is to be implemented in practice. The challenges and controversies surrounding windfall profits of power plants during the gas and electricity price crisis are just one example. In this context, generators were supposed to transfer a portion of the extremely high revenues from electricity sales, as estimated by production volume and spot price. The energy volumes marketed in futures markets or bilateral contracts were not to be taken into account.

Implementation proved to be complex, partly due to the large number of possible contract constellations. The control of mandatory hedging could motivate market participants to enter into many more and more complex contract structures that fulfil the respective regulatory requirements without actually providing the desired hedging and thus investment support. Monitoring all of these contracts appears to be difficult to implement.

Standardisation necessary for effective control. A standardised product would therefore have to be defined, which all players would have to use. All other contract structures would have to be prohibited so that they are not used by companies to neutralise the effect of the mandatory contracts. Against this background, it can be assumed that a hedging obligation to increase security of supply must be accompanied by a standardisation of all contracts and very general requirements for the future electricity demand to be hedged.

Volume forecasts are required. At the same time, a reference value would have to be defined for the electricity procurement of a company or the electricity demand of an energy supply company to be hedged. Forecasting this demand is complex, and it is not clear what possibilities a regulatory authority has to monitor such a forecast if an electricity customer or energy supply company forecasts a fall in demand due to a loss of customers in order to reduce the (expensive) hedging obligation. This would possibly limit the concrete implementation of a hedging obligation to ex-post proof of hedged demand and have a similarly limited effect as the decentralised capacity mechanism discussed above.

4 How well can capacity mechanisms unlock flexibility potentials other than dispatchable power plants?

Qualitative discussion of capacity mechanisms and flexibility. Based on previous experience with capacity mechanisms and their economic impact, various opportunities and risks can be derived for the development of flexibility potential beyond dispatchable power plants. The following section discusses how effectively such flexibility potential can be utilised within the framework of the capacity mechanisms considered here and what requirements arise.

The multitude of these challenges means that the overwhelming majority (83%) of the capacity supported by the capacity mechanisms in Europe is fossil-fuelled power plants, as well as nuclear or hydropower plants. In contrast, demand flexibility and batteries only play a marginal role: in 2023, only 5.6 GW (three per cent) of the 176 GW of capacity supported was demand flexibility or battery storage. Ireland had the highest share of flexibility and storage among the capacity markets in 2023, at just under nine percent (ACER 2023a).

4.1 Restrictive requirements of capacity markets can rule out flexibility options

Discriminatory regulatory requirements. For all capacity mechanisms, the regulator must define specific requirements that the capacity providers must fulfil. It is difficult to define these requirements in such a way that they do justice to the many different characteristics of supply-side and demand-side flexibilities and different types of energy storage. In practice, the requirements listed below are often specified in such a way that they represent obstacles or even exclusions for flexibility options.

Lead times for investments. The requirements for the period between allocation and actual capacity delivery influence the size of the participating plants. For example, tenders with short lead times can rule out investments in large plants, which is why longer lead times are chosen. However, this is a disadvantage for small players with technology options that can be implemented quickly. Demand-side flexibility investments are developed together with investments in new heating networks or the electrification of an industrial production process. These investment measures must be coordinated with many requirements and stakeholders - they would therefore be difficult to fit into the tight time frame resulting from the lead time of a capacity mechanism.

Contract terms. Investors in large power plants usually favour a long contract term to secure their revenue streams. However, this can inhibit flexible consumers on the industrial side, as the obligation to maintain their flexibility over the long term also obliges them to maintain their production as the basis for electricity procurement for the same period (ACER 2023b). For such longer-term periods, companies prefer to maintain greater flexibility in their future production activities.

Minimum size. Excessive requirements for the minimum size of installations can be considered an exclusion criterion for small-scale options, which applies in particular to demand-side flexibilities. For example, plants participating in the Irish capacity mechanism must have a minimum capacity of 10 MW.

Pre-qualification as proof of reliability. Requirements regarding the probability of failure in conjunction with penalties, i.e. contractual penalties, can have a discriminatory effect against flexibility. Small plants, although they have a high probability of failure individually, can offer reliable security of supply overall if their probabilities of failure are uncorrelated. However, if penalties for outages are calculated independently of the size of the plant, this advantage is not recognised, and small plants are disadvantaged. For capacity markets, the question also arises as to whether the correlated risk of an interruption in fuel supply - for example in the case of natural gas - should be taken into account in order to reduce the capacity contribution and thus the revenues of gas-fired power plants accordingly.

De-rating of the capacity contribution. An important question for flexibility technologies is how much their capacity contribution is discounted (so-called de-rating) if they are only available for a limited period of time or at certain times. The capacity contribution of a storage system therefore depends on the number of hours for which energy can be stored and the expected demand in the electricity system. This demand and the technology-specific de-rating factor will therefore also change over time (Fraunholz et al. 2021). The trust of grid operators and regulatory authorities in the reliability and deployability of flexibility options plays a particularly important role here. It can be assumed that regulatory authorities and grid operators will only recognise flexibility in the capacity mechanism to the extent that they have gained positive experience with its use. As many of these technologies are still barely established on the market, there is a risk that they would be disadvantaged in a centralised capacity market.

Reliability reserve without qualification requirements for flexibility options. In capacity markets, it is necessary for all participating technologies to fulfil qualification requirements (see chapter 3.1.2 and 3.2.2), which discriminates against and restricts flexibility options. In contrast, flexibility options should not be included in the reliability reserve at all and are therefore not subject to any qualification requirements. Instead, they should be able to operate freely on the market and gain experience. The generation technologies within the reliability reserve function exclusively as back-up, which are rarely activated and may no longer be activated at all in the future.

4.2 Capacity market weakens revenue opportunities and thus flexibility options on the market

Indirect penalisation of flexibility options. Demand-side flexibility is not only insufficiently taken into account in capacity markets but is also penalised by an indirect effect: An effective capacity market ensures investment in additional generation capacity. This reduces the frequency of hours with high electricity prices. However, a reduction in the electricity price differences between high- and low-price hours also reduces the revenue opportunities for all flexibilities and thus their profitability. This means that less flexibility potential can be utilised. In a dynamic perspective, less experience can be gained with them and there is less "learning by doing".

This negative effect is reinforced by the fact that regulatory authorities, grid operators and ultimately also politicians, especially in centralised capacity markets, assume very clear and explicit responsibility for maintaining sufficient capacity in order to avoid supply bottlenecks. As supply bottlenecks can quickly become a political issue, the aforementioned actors will tend to put too much rather than too little capacity out to tender. In doing so, they accept that the costs of passing on the capacity payment to electricity customers will increase. At the same time, however, the larger the capacity market, the more the revenues from flexibility options will tend to decrease, meaning that investments in these flexibilities will decline even further.

Capacity mechanisms weaken hedging in futures markets. Furthermore, the shift of scarcity signals from the energy market to the capacity market could also weaken the need for hedging in the energy market and thus trading activities and hedging in futures markets. This would also discriminate against the development of flexibility technologies, which would be even more

dependent on hedging with futures products than power plants that can participate in the capacity market due to their disadvantage in the capacity market.
This weakening of forward market hedging can occur in the centralised capacity market, for example, by designing it as a reliability option. With these, capacity market participants are obliged to make repayments in times when electricity prices are above a set value, which are passed on to electricity customers. This reduces the motivation of electricity customers to hedge further. At the same time, the possibility for electricity producers to offer forward products is restricted, as they would then be obliged to pay both under a reliability option and a forward product in the event of high prices. In the decentralised capacity market, the weakening occurs because market participants are encouraged to trade capacity products where scarcity prices should arise analogously to the scarcity prices of an energy market. In the decentralised capacity market, all market participants would therefore have to trade two product types in parallel, which would result in increased complexity, higher transaction costs, higher market access barriers and reduced liquidity.

Reliability reserve strengthens the electricity market and thus investments in flexibility. In contrast, a system with a reliability reserve ensures sufficient generation capacity for all eventualities and thus copes with the political reality. However, these capacities are only utilised as a secondary priority when prices are very high, for example at 500 euros/MWh. Until then, electricity prices can develop freely in line with variations in generation costs and scarcity. The uncertainty that would otherwise exist regarding possible regulatory interventions is greatly reduced by the clear definition of the trigger price. This means that all flexibilities can prove themselves on the market and be utilised, motivated by the revenue and hedging options of a functioning energy market. Therefore, the reliability reserve creates a learning environment for flexibility technologies by safeguarding the energy market instead of restricting it.

4.3 Strengthen incentives for flexibility on the demand side by passing on the costs of the capacity mechanism

Allocation of capacity requirements in the decentralised capacity market. In the decentralised capacity mechanism, the German government proposes to use electricity consumption in hours when energy is scarce in the overall system as a basis for calculating the capacity certificates to be held, similar to the implementation in France (BMWK 2024). In France, for example, time windows are defined in advance for 15 days relevant to the obligation, on which electricity consumption is measured, spread over the critical months of a year. The capacity requirements are therefore allocated to the consumers in proportion to their demand during the assessment period. This creates incentives to develop and utilise flexibility potential on the demand side in order to reduce demand during these hours.

Cost allocation in the centralised capacity market. In the centralised capacity market, the costs of capacity payments are allocated to consumers. In theory, this could be done in the same way as the allocation of capacity requirements in the decentralised capacity market by defining assessment periods. In this way, similar incentives for flexibility on the demand side could be created if the costs of the capacity market are allocated to the balancing group managers in proportion to the load during these peak hours.

False incentives due to cost allocation over the assessment period. The predetermination of the hours that serve as the basis for assessment creates an incentive to reduce electricity consumption in these predefined time windows, for example by using storage facilities, to reduce the amount of capacity certificates that need to be held. This becomes problematic if the assessment period happens to fall exactly in the days before a period of low wind and solar production. Flexibility options and storage facilities are then already discharged and can no longer help to secure the load in an actual system-critical situation. This shows that the proposal for a decentralised capacity mechanism originates from a time of inflexible electricity demand and largely weather-independent electricity generation. If these assumptions no longer apply, a corresponding distribution of costs could create false incentives for the use of flexibility, which could jeopardise system security.

Limited hedging via futures markets. If flexibility is incentivised via pricing on the energy market, electricity customers have an interest in hedging their price risks with forward products. This creates the opportunity for investors in flexibility options to hedge their revenues by selling such forward products. This possibility does not arise with comprehensive capacity markets if the incentives for the development of demand-side flexibility options to reduce electricity procurement in hours considered critical are created by a regulatory obligation (decentralised capacity market) or an allocation of the costs of the capacity market (centralised capacity market). The cost risks arising from such a requirement are subject to major regulatory risks. It is therefore difficult to imagine the development of a liquid futures market to hedge them.

Futures markets for flexibility desirable. A liquid futures market for flexibility is valuable for all market participants. One possible product could be a price spread that hedges the price difference between the four hours with the highest and lowest electricity prices of a day. This can be signed by investors in flexibility with a corresponding storage volume, but also serves as a good hedge for various flexibility requirements (Neuhoff et al. 2023). Such a forward product creates transparency for the development of the most cost-effective flexibility potential, creates visibility of future flexibility requirements and enables non-discriminatory hedging of flexibility requirements for all players. Last, but not least, such a market can create a framework in which players with great flexibility potential can tap into it, even if they themselves have low financing capacities. This could apply to district heating operators and industrial park operators, for example. They can make larger investments if they can sell the flexibility to third parties as security.

5 Interim conclusion: only two options make a reliable contribution to security of supply

Overview of strengths and weaknesses. The basic characteristics, strengths, and weaknesses of the various capacity mechanisms are summarised again in Table 1.[14]

Open questions regarding decentralised options. A consideration of all aspects leads to the conclusion that both the decentralised capacity market and mandatory hedging on futures markets raise open questions and do not appear practicable to implement. A key argument against the decentralised capacity market is that it does not provide sufficient incentives for long-term investments due to the relatively short lead time in certificate trading. Mandatory hedging on futures markets could only lead to reliable security of supply if hedging mechanisms and products are highly standardised, which would correspond to major interventions in the energy market. Both options also share the fact that, although they are regulated in a decentralised manner, they are associated with a high level of control and administrative effort for central bodies.

Combined capacity market complex and untested. The model of a hybrid capacity market as a combination of a centralised and decentralised mechanism currently favoured by the German government raises further questions. The combination of a centralised and decentralised capacity market not only has the potential to combine the advantages of both concepts, as is hoped for in the BMWK options paper. Rather, the respective disadvantages of the two capacity mechanisms with regard to the lack of investment security and the incentivisation of demand-side flexibility could also be combined. Furthermore, a combined capacity market has so far been completely untested internationally. Its practical implementation inherits the risk of unexpected interaction problems between the two market segments, which are not yet understood from today's perspective. This also makes it seem implausible that a well-prepared combined capacity market could come into force in the near future.

Central capacity market and reliability reserve as remaining candidates. The options of a centralised capacity market and the reliability reserve therefore appear to be more plausible and can be implemented in the relatively short term in order to guarantee security of supply in the long term. However, they have different effects on investments in demand flexibility, which was

[14] The combination of a centralised and decentralised capacity market is not listed separately in the overview table. Due to the still unclear design of a combined capacity market, it is still difficult to foresee how the advantages and disadvantages of a decentralised and centralised capacity market could come into play.

already discussed in chapter 4 qualitatively. In order to substantiate these arguments quantitatively, they are analysed in chapter 7, illustrated with the results of an electricity sector model, which show the effects of both mechanisms on the electricity market and in particular on the realised demand flexibility.

Table 1: Options for the design of capacity mechanisms: comparison of key characteristics, strengths and weaknesses

	Decentralised capacity market	**Centralised capacity market**	**Reliability reserve**	**Mandatory Hedging**
Volume/ Capacity planning	Determined in a decentralised manner by market participants	Total capacity in the system is determined centrally by the regulator	Regulator determines the size of the reserve	Unclear, ultimately probably only verifiable ex-post
Procurement	Bilateral agreements	Central auctions	Central auctions	Bilateral agreements
Product	(Capacity) certificates	Dispatchable capacity	Reserve capacity	Forward products
Revenue from subsidised capacity	Revenues for capacity certificates in addition to electricity market revenues	Capacity payments in addition to electricity market revenues	Payment for provision and call-off for power plants in reserve	Revenues from the futures market (possibly higher than electricity market revenues)
Control variables for politics/state	Penalties Security services Trigger price De-rating factor per technology	Volume, penalties Lead times, contract terms Hedging De-rating factor per technology	Volume Trigger price	Unclear, ultimately probably definition of standardised forward products
Required lead time	Rather high	Medium to high	Low, existing system	Unexplained
Spatial differentiation	Complex to realise	Possible	Possible	Complex / unexplained
Strengths	"Breathing" mechanism, responsibility for suppliers	High investment security for power plants, ensures security of supply	Creates investment incentives and learning environment for flexibility, ensures security of supply, already established mechanism	Expansion of existing hedging mechanisms
Weaknesses	Administrative and control costs, credible penalties and securities, ex-post determination of volume, uncertain effect	Risk of oversizing, low openness to technology and innovation	Costs, should trigger price of reserve for long periods pricing	Effectiveness unclear, administrative and control costs, credible penalties and securities
Consideration of demand-side flexibility	Limited direct consideration and weakening of investment incentives in the electricity market, possibly incentives through cost pass-through structure	Limited direct consideration and weakening of investment incentives in the electricity market, possibly incentives through cost pass-through structure	Creation of investment incentives and learning environment for flexibility in the electricity market, strengthens hedging in futures markets	Risk that standardisation discriminates against flexibility options

6 Modelling background

This chapter describes the basics of the modelling, the results of which are presented in chapter 7. Chapter 6 discusses the electricity sector model, the underlying assumptions, the modelled demand-side flexibility, the policy scenarios, as well as the costs and technical parameters. Finally, the limitations of the modelling and their influence on the model results are critically discussed.

6.1 The electricity sector model “DIETER”

Model overview. The "Dispatch and Investment Evaluation Tool with Endogenous Renewables" (DIETER) is an open-source electricity sector model.[15] The model minimises the electricity sector costs and, depending on the application, other costs of flexibility and sector coupling technologies. In order to realistically represent the variability of renewable energy sources or, for example, the use of storage, all contiguous hours of a full year ranging from the beginning of January to the end of December are modelled. The variables determined in the model are the electricity sector costs, the optimal capacities of various technologies and their hourly utilisation. DIETER has been continuously developed at DIW Berlin for over ten years and has already been used in a large number of studies and is the basis for a number of peer-reviewed scientific publications (Zerrahn and Schill 2017, Schill and Zerrahn 2018, Stöckl et al. 2018, Schill 2020, Schill and Zerrahn 2020, Gaete-Morales et al. 2021, Roth and Schill 2023, Gaete-Morales et al. 2024, Roth et al. 2024).

Assumptions. The model used is a linear cost minimisation problem. It is implicitly assumed that the electricity market is a fully competitive market in which all players bid only at their marginal costs, are perfectly informed about all other players and have perfect foresight for the year. The model results can therefore be interpreted as the outcome of an ideal, frictionless market.

Input data. Key input data for the model are time series of demand for electricity, heat and green hydrogen, time series on the availability of fluctuating renewable energies, as well as cost assumptions and boundary conditions for investments in various technologies. Even if the focus of the analysis presented here is not on concrete figures, but rather on fundamental insights into

[15] The model used for this analysis, as well as the input data and output data, can be found in a public GitLab repository: https://gitlab.com/diw-evu/projects/sicher

the market effects of the two different capacity mechanisms, all input data can be viewed publicly in the repository mentioned above.

Stylised model. To simplify the analytical framework, only the German electricity sector is modelled, excluding electricity exchange with neighbouring countries. The electricity grid within Germany is also not modelled. It is implicitly assumed that there are no structural bottlenecks in the German transmission or distribution grids.

Scenarios. Two policy scenarios are analysed: a central capacity market and a reliability reserve. For each policy scenario, the optimal capacities in a predetermined weather year are determined. For this purpose, the year 2010 is used, which can be considered an average year in some respects among the years analysed. In a second step, these capacities are tested in different weather years to analyse the effects on prices and the rest of the electricity sector.

Endogenous and exogenous parts of the power plant portfolio. The capacities of fluctuating wind and solar energy are fixed to the German political targets for 2030 in all scenarios. Power plant capacities such as hydropower and bioenergy are also fixed exogenously. For the weather year 2010, the remaining part of the power plant fleet is determined exogenously for each of the two policy scenarios. This includes in particular the capacities of gas-fired power plants, battery and hydrogen storage as well as the investment in various flexibility options on the demand side. These capacities are then fixed for the model runs of other weather years (more details in section 6.3).

Stylised representation of sector coupling. In order to keep the analysis as lean as possible, sector coupling technologies are not explicitly modelled for the most part, but are considered as part of the price-inelastic electricity demand (e.g. electromobility and decentralised heat pumps).[16] In contrast, heating networks that are operated with large heat pumps are modelled and explained in the next section.

[16] In other DIETER analyses, these sector coupling technologies are explicitly modelled as potentially flexible demand, see Gaete-Morales et al. (2024) and Roth et al. (2024).

6.2 Demand-side flexibility options considered

Three categories of demand-side flexibility. The model comprises three different categories of demand-side flexibility options assumed for the year 2030. These include various types of load management potential ("demand response" potential) in energy-intensive industry, in process heat and in the district heating sector. Their potential and costs are analysed and estimated based on literature data. As the electricity sector model is used to analyse the use of cost-optimised flexible demand in 2030, the possible load flexibility potentials of the respective areas under consideration were forecast. This includes the potential for load changes, their maximum activation duration in hours and the associated costs. In this analysis, it is assumed that the various consumers only need to invest in energy or product storage systems in order to tap into demand-side flexibility, while the relevant electrical power already exists.

Energy-intensive industry. Electric steel, aluminium, paper, cement, chlor-alkali electrolysis and air separation are characterised by particularly high electricity intensity (Arnold et al. 2018) and were therefore analysed separately based on the available literature.[17] The load flexibility potential of the remaining energy-intensive industries was determined on the basis of the information on electricity demand provided by BAFA as part of the special equalisation scheme application procedure 2021 for the limitation of the EEG surcharge.[18] Figure 2 shows the resulting potential for flexible loads in energy-intensive industry in 2030. The electricity sector model decides endogenously, based on the storage and activation costs, the maximum amount of energy that can be shifted. For example, a maximum storage capacity of 3h x 1558 MW = 4674 MWh can be added for all technologies with a duration of 3 hours. Technologies with correspondingly longer activation times can also be equipped with larger storage facilities. To reduce complexity, it was assumed for the load flexibility potentials that electricity-intensive parts of a production process can be shifted in time by storing the products in a physical storage facility (load shifting). The alternative of load shedding, i.e. the shifting of electricity procurement without production, was not taken into account.

[17] Data basis for the individually considered energy-intensive industries: Deutsche Energie-Agentur GmbH (dena) 2010, Gils 2014, Helin et al. 2017, Klaucke et al. 2017, Klaucke et al. 2023, Klobasa et al. 2013, Kollmann et al. 2015, Langrock et al. 2015, Paulus and Borggrefe 2011, Steurer 2017 and VDE study 2012.

[18] Data basis for other energy-intensive industries: Calculation of installed electrical output via privileged electricity volumes for electricity-intensive companies in accordance with Section 64 (1) EEG until 2022 (Federal Office of Economics and Export Control (BAFA) 2021), taking into account an increase in future electricity demand of 39 % (Boston Consulting Group 2021). Assumption of flexibilisable output as 10 % of installed electrical output.

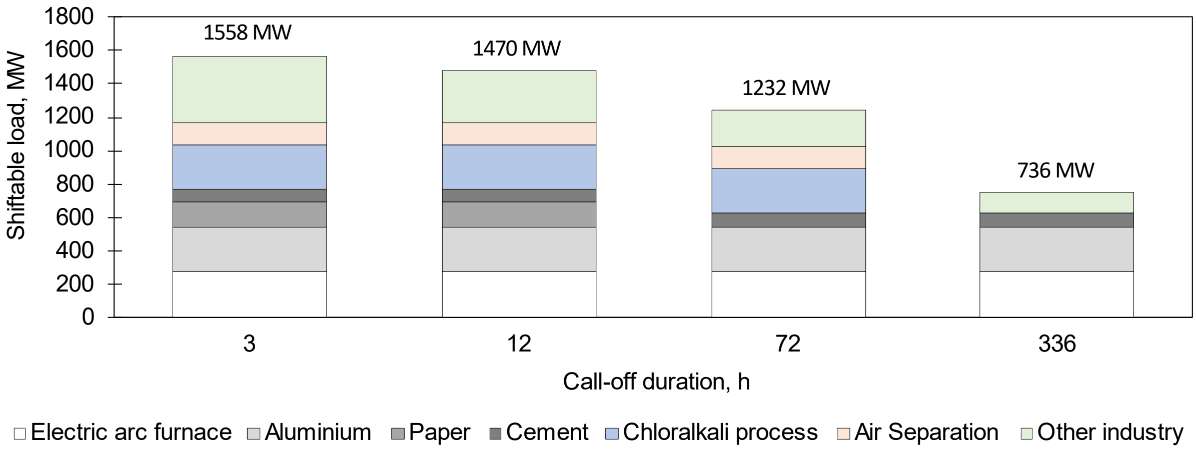

Figure 2: Forecasted flexible load in MW_{el} of the individual industrial processes for the year 2030 per available duration in hours (h)

Process heat. Process heat accounts for the largest share of energy consumption in industry (Fraunhofer ISI 2024), with natural gas currently being by far the dominant energy source. Thus, electrification of process heat within the technical possibilities is essential for achieving the climate targets by 2030 (Boston Consulting Group 2021). In contrast to space heating, which is seasonally temperature-dependent, the demand for process heat is constant throughout the year due to its coupling to industrial production (Gils 2014). Against this background, load management is of great importance in the context of the electrification of process heat and was taken into account in this analysis. The calculation of the future electrical energy demand for the provision of process heat was based on Kemmler et al. (2017). Table 2 shows the forecast for the electrical energy demand for the provision of industrial process heat based on the assumptions that were included in the model calculations.[19] The power that the process heat can call up is determined in the same way. However, the amount of energy, i.e. the size of a heat storage tank, is a free variable in the model.

[19] Process heat up to a temperature level of 400 °C was analyzed. It was assumed that the process heat for a temperature level of up to 160 °C is provided by a high-temperature heat pump and for the temperature range 200-400 °C by an electrode boiler (Fleiter et al. 2023). The economic sectors of quarrying, glass and ceramics, processing of stone and earth, metal production, non-metals and foundries, metalworking and mechanical engineering were excluded. The background to this is that in their production processes, heat is predominantly used directly in the processes and not indirectly, e.g. via process steam. At the same time, the temperatures required here are at the upper limit of the temperature levels considered here (Fleiter et al. 2023). Thermal storage takes place using a solid fuel storage system with a storage efficiency of 90 % (Profaiser et al. 2022) and the maximum installed storage capacity is 30 % of the installed electrical capacity for process heat. The maximum heat storage duration is 72 h. Due to the low investment costs, the installed excess capacity for process heat is realized via electrode boilers with a thermal efficiency of 99 % (Fleiter et al. 2023). The storage losses as a percentage of capacity per day are 3 %/d (Arnold et al. 2019).

Table 2: Forecast of future demand for electrical energy for the provision of industrial process heat

Process heat temperature range	Thermal energy requirement for process heat[20]	Electrical energy requirement via high-temperature heat pump	Electrical energy requirement via electrode boiler
< 100 °C	67 TWh_{th}/a	18.1 TWh_{el}/a	
100-160 °C	70.2 TWh_{th}/a	19 TWh_{el}/a	
160-400 °C	33.1 TWh_{th}/a		33.4 TWh_{el}/a
Total		70.5 TWh_{el}/a	

District heating. In order to take into account the flexibility potential from the sector coupling of district heating and the electricity market, a simplified district heating market was modelled. It is assumed that an average of 95 TWh of heat per year must be covered by this district heating market, which corresponds to a good 30 percent of the heat demand in apartment blocks and commercial buildings. It is assumed that this district heating demand is covered entirely by large ground source heat pumps.[21] The possibility of load shifting is modelled by an integrated hot water storage tank, the size of which is determined endogenously by the model, while the heat and electricity output is exogenous. The flexibility of decentralised heat pumps is not taken into account, although these can - to a limited extent - also contribute to the flexibility of the electricity system (Roth et al. 2024).

6.3 Scenarios, technologies and data

Scenarios. Two policy scenarios are defined for the analysis, in which the assumed capacity mechanisms differ:

1. In the scenario of a **centralised capacity market**, this supplements the electricity market by stipulating a minimum amount of firm capacity in the model. The model must provide at least 105 GW of capacity, which can be covered by gas (gas turbine and combined-cycle gas turbine power plants), oil, bioenergy, reservoir, and hydrogen power plants. This target was set so that in all the weather years the residual load (normal electricity demand and electricity demand for heat minus generation from fluctuating renewable energies) can be covered by the capacity from the capacity market, plus a safety

[20] Data basis for the thermal energy demand for process heat based on Kemmler et al. (2017)

[21] Heat is stored in a liquid storage tank with a storage efficiency of 90 % and storage losses as a percentage of capacity per day of 2 %/d (Arnold et al. 2019).

margin of 5 GW. However, only gas and hydrogen power plants are available to the model as free variables, as the capacities of the other technologies are predetermined.

2. In the scenario of a **reliability reserve**, the electricity market is supplemented by a fleet of reserve power plants located outside the electricity market, which are only utilised when the electricity price is 500 euros per megawatt hour. In the model, the size of the reserve, i.e. its total capacity, is determined in such a way that it can cover demand in all the weather years.

Demand flexibility is assumed to be neither in the capacity market nor in the reserve. In both scenarios, it is assumed that demand flexibility does not receive any payments from the capacity mechanisms but is financed exclusively from the revenues or savings in the energy market. A two-stage procedure is applied. In the first stage, these scenarios are calculated for the - average weather year 2010 in order to obtain the cost-optimised power plant capacities and flexibility potentials. In the second stage, both scenarios and the previously set power plant capacities are tested in different weather years and the impact on prices is analysed.

Exogenous parts of the power plant fleet. The electricity market model has several generation and storage technologies at its disposal in order to meet the demand for electricity as cost-effectively as possible. Renewable energies, whose capacities are fixed at the values targeted by the German government for 2030 and are not optimised by the model, are central to the electricity supply: Photovoltaics (215 GW), onshore wind power (115 GW), and offshore wind power (30 GW). In addition, oil-fired power plants (2.8 GW) and bioenergy power plants (11 GW) are available to the model in terms of dispatchable capacity, the capacity of which is also fixed exogenously. The same applies to run-of-river power plants (3.9 GW), run-of-river power plants (0.8 GW capacity and 237 GWh of energy) and pumped storage power plants (8.5 GW storage capacity and 863 GWh of energy). For the modelling calculations, it is assumed that the coal phase-out will be completed by 2030. This means that no more coal-fired power plants will be available to the system to ensure security of supply.

Endogenous parts of the power plant fleet. The model is free to decide on the level of installed capacity of gas-fired power plants (gas turbine and combined-cycle gas and steam power plants), as well as battery storage and hydrogen storage, including electrolysers and hydrogen power plants. In addition, there are investments in the above-mentioned demand-side flexibility options.

Techno-economic input data. The total demand for electricity is assumed to be 715 TWh for all years. Added to this is the amount of electricity required to cover district heating, which averages a good 21 TWh across all scenarios and years. The time series for demand and availability come from ENTSO-E's ERAA 2021. The time series for heat demand and efficiency of heat pumps come from Ruhnau and Muessel (2022). Table 3 shows the assumed costs and technical parameters of various generation and storage technologies that the model can decide on endogenously.

Table 3: Cost and efficiency parameters

Generation					
		Costs			
		Variable [€]		Investment	Fix
Technology	Efficiency	Fuel	CO2 price	[€/MW]	[€/MW]
Gas turbine (OCGT)	0.4	26.028	130	400000	15000
Combined cycle gas and steam turbine (CCGT)	0.542	26.028	130	800000	20000

Storage								
Technology	Efficiency			Costs				
	In	Out		Variable [€/MW]		Investment [€/MWh]		
	save	save	Stand	Ins.	Excl.	Ins.	Excl.	Energy
Battery	0.97	0.97	1	0.3	0.3	50000	10	300000
Hydrogen	0.73	0.6	1	1.2	1.2	305000	850000	200

6.4 Discussion: Effects of model restrictions

All model analyses are based on simplifications. Like any model-based analysis, this one is only a simplified representation of reality. The results and the exact figures shown are primarily illustrative in nature and intended to show the mechanisms of action. The following section briefly discusses the direction in which some of the main model limitations are likely to have a qualitative effect.

Deterministic model. The analysis was calculated using a deterministic model with perfect foresight. This may result in the utilisation of demand-side flexibility technologies tending to be overestimated compared to a situation with uncertainties regarding, for example, future electricity generation from renewable energies or market price developments.

No grid bottlenecks. Another limitation of the model is that it does not model an electricity grid. It is implicitly assumed that sufficient grid capacity is available and that there are no bottlenecks in the transmission and distribution grids. As this is unlikely to be the case in Germany in the foreseeable future, this analysis cannot provide any information on the interactions of capacity mechanisms or demand-side flexibility options with the electricity grids or on optimal locations for power plants or other controllable capacities.

No consideration of other important flexibility options. In the model, there is no electricity trading with neighbouring countries and no flexibility in other sector coupling technologies such as electric vehicles or decentralised heat pumps. This means that the flexibility potential in the model is likely to be lower than in reality, which in turn may result in an increased need for dispatchable power. The results of this study can therefore be regarded as a "worst case" for the weather years analysed here. A more comprehensive investigation could include further flexibility options and even more weather years in order to achieve even more robust results.

At the same time, the 2030 perspective neglects the fact that the use of fluctuating renewable energies is likely to increase significantly until the mid-2040s. Accordingly, the benefits of demand-side flexibility in particular are likely to increase further over time and tend to be underestimated here. Investment options in flexibility potential are likely to have even greater energy industry benefits after 2030.

7 Model results show the effect of capacity mechanisms on demand-side flexibility

Quantitative illustration of the flexibility effects. The two options that were assessed as the most promising in Chapter 5 differed significantly in terms of their impact on the energy market and the development of demand-side flexibility. Qualitatively, this was already discussed in Chapter 4. This is now illustrated quantitatively below. The open-source electricity sector model DIETER, which has been actively developed at DIW Berlin for over ten years, was used to determine a minimum-cost power plant portfolio for given demand and weather data and its utilisation in all consecutive hours of the year. There is also the option of investing in demand-side flexibility. Two different policy scenarios are analysed: (1) a comprehensive capacity market with a size of 105 gigawatts, in which primarily dispatchable power plant capacity is contracted, and (2) a reliability reserve, which is activated at a price of 500 euros per megawatt hour.

Insights, not numbers. The primary aim of the model analysis is not to generate policy-relevant figures on the dimensioning of the capacity mechanisms, the composition of the power plant fleet or the total costs. Rather, the aim is to create an understanding of the different effects of the capacity mechanisms on the utilisation of demand-side flexibility options. To this end, the electricity sector model is intentionally simplified in some respects. In particular, it only depicts the German electricity sector and does not include interactions with neighbouring countries.[22] The methodological details of the modelling and key assumptions regarding input parameters can be found in chapter 6 and in a freely accessible repository.[23]

7.1 Capacity market reduces price incentives for flexibility

Comparison of price-duration curves. A key difference between a centralised capacity market and a reliability reserve is the fact that the latter is only activated in the event of high prices on the wholesale electricity market, while the power plants of the capacity market operate continuously on the electricity market. Figure 3 illustrates this. It shows the price-duration curves for both scenarios. A price duration curve sorts all hourly prices for a year, starting with the highest price on the left and ending with the lowest price on the right. Differences arise above all in the few hours with the highest prices (left panel Figure 3). During the vast majority of other hours

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[22] In other analyses with the DIETER model, the European electricity network is often modelled. For example, the effect of the European electricity exchange on storage requirements was recently analyzed (Roth and Schill 2023).

[23] The model code and all input data are freely available on GitLab: https://gitlab.com/diw-evu/projects/sicher

of the year, however, the results for the central capacity market and the reliability reserve hardly differ (right panel, Figure 3). Here, the differences between the weather years are significantly greater than those between the two policy scenarios.

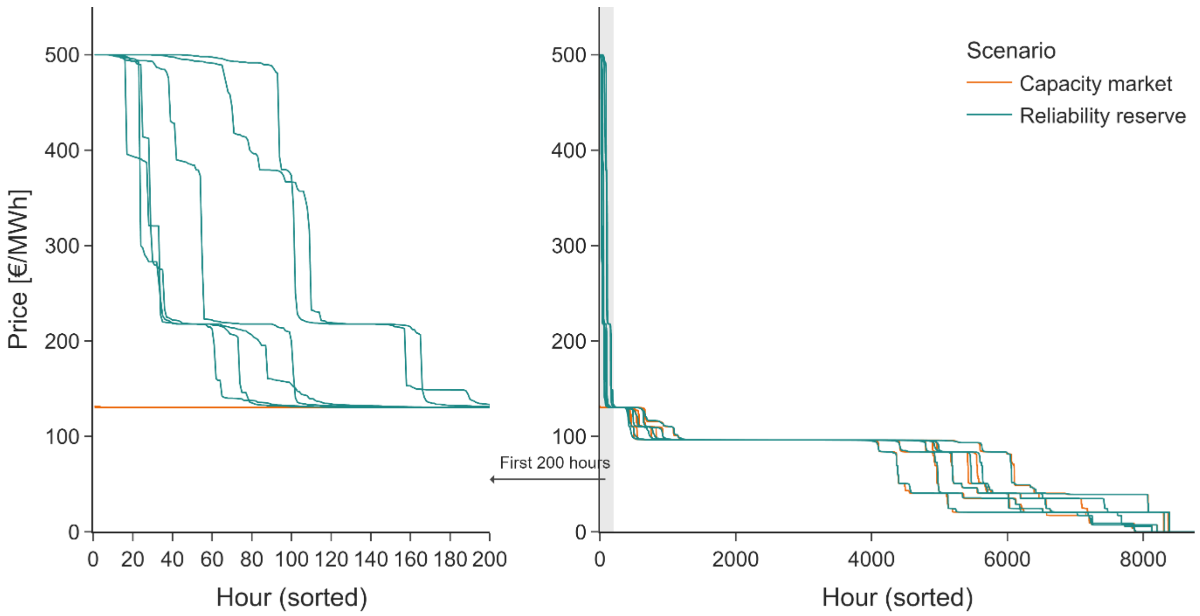

Figure 3: Price duration curves in the electricity wholesale market for the capacity market and reliability reserve in different weather years (2009 -2014)

Peak prices in the capacity market are much flatter. For around 3-7 days (72 to 168 hours) per year, prices differ greatly between a capacity market and a reliability reserve (left panel, Figure 3). In a centralised capacity market, there is always sufficient generation capacity from gas-fired power plants on the market during these hours, meaning that their marginal costs always determine the electricity price. The resulting maximum price of the capacity market is around130 euros per megawatt hour, which corresponds to the marginal production costs of a gas turbine in the model (variable costs + fuel price + CO_2 price). However, what looks good at first glance in the capacity market scenario - "flat" prices - reduces the attractiveness of investments in flexibility options. Furthermore, electricity customers in the capacity market are exposed to the additional costs for capacity payments, which are not included in the price-duration curve shown.

Reliability reserve enables higher price variations within the year. In the scenario with a reliability reserve, on the other hand, prices gradually rise to up to €500 per megawatt in some hours. The revenues from these prices above the marginal costs of gas-fired power plants enable investments in further flexibility options in the electricity market (more details in the following chapter 7.2). These revenues vary only slightly between years. This means that corresponding investments can be realised with only moderate hedging through futures markets. The electricity price never exceeds €500 per megawatt hour, as in this case the power plants of the reliability reserve are used, which effectively cap the price at €500.

7.2 Reserve leads to greater expansion of flexibility

Capacity market only leads to low investment in flexibility options. The model analysis illustrates the extent to which a comprehensive capacity market can restrict the development of demand-side and storage flexibility potential in the electricity market (Figure 4). The reason for this is that the capacity market makes so much power plant capacity available that wholesale prices only rise up to the variable costs of the most expensive power plants in the capacity market (see previous section). This reduces the revenues for flexibility and therefore only leads to the realisation of low flexibility potential. Demand-side flexibility is therefore not only disadvantaged in the central capacity market by the fact that it is not included in the capacity market itself, but also indirectly by the fact that prices in the electricity market are effectively capped.

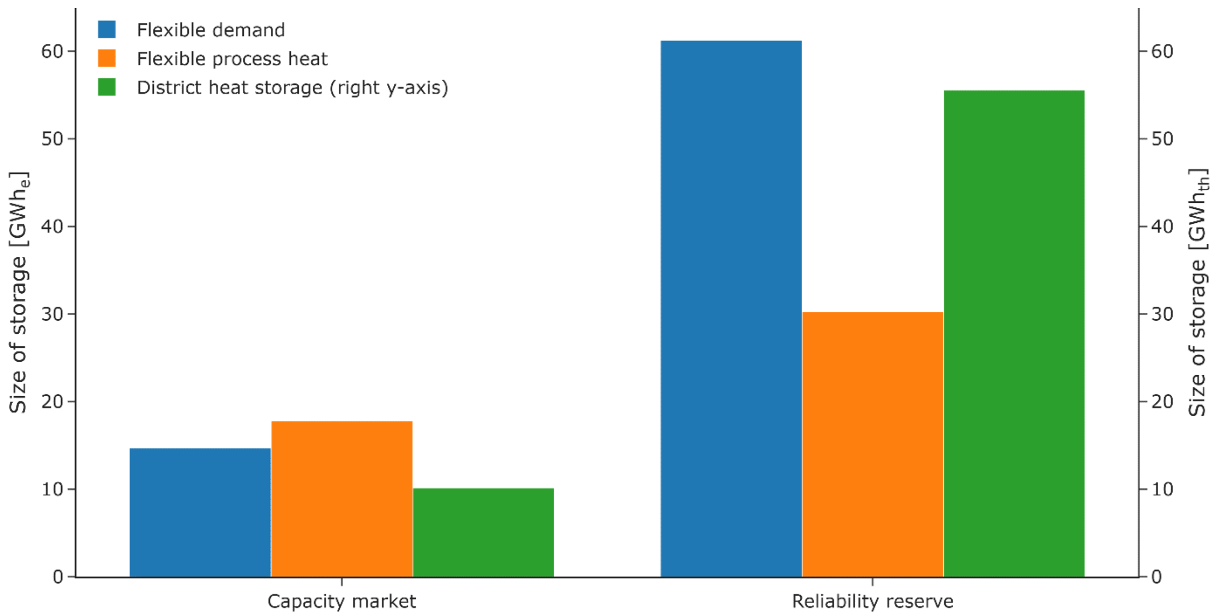

Figure 4: Comparison of investments in different types of storage in the capacity market and in the reliability reserve scenarios

Reliability reserve provides stronger incentives for flexibility. In contrast, the expansion of flexibility is incentivised much more strongly if the electricity market is secured by a reliability reserve. The modelling results show that with a reliability reserve, almost four times as much is invested in storage energy for flexible demand as with a capacity market. This storage corresponds to the sum of all storage energy for flexible demand described in the previous chapter. With more storage energy, the model is able to shift more demand. In this modelling context, investments in storage mean that a physical storage facility is built in which products are stored so that electricity-intensive parts of a production process can be postponed (cf. chapter 6.2.). The investment volume in energy storage roughly doubles for flexible process heat. In the case of district heating energy storage, the reliability reserve even leads to more than five times as much investment.

7.3 Different effects on the power plant portfolio

Capacity market leads to high investments in power plants that participate in the electricity market. The output of power plants that participate directly in the electricity market is significantly lower in the case of the reliability reserve than in the case of a comprehensive capacity market (Figure 5). There are differences particularly in the case of open-cycle gas turbines (OCGTs), of which significantly more are kept in reserve in the case of the capacity market. In the case of a reliability reserve, on the other hand, extensive power plant capacities are held in reserve, but do not participate in the regular electricity market.

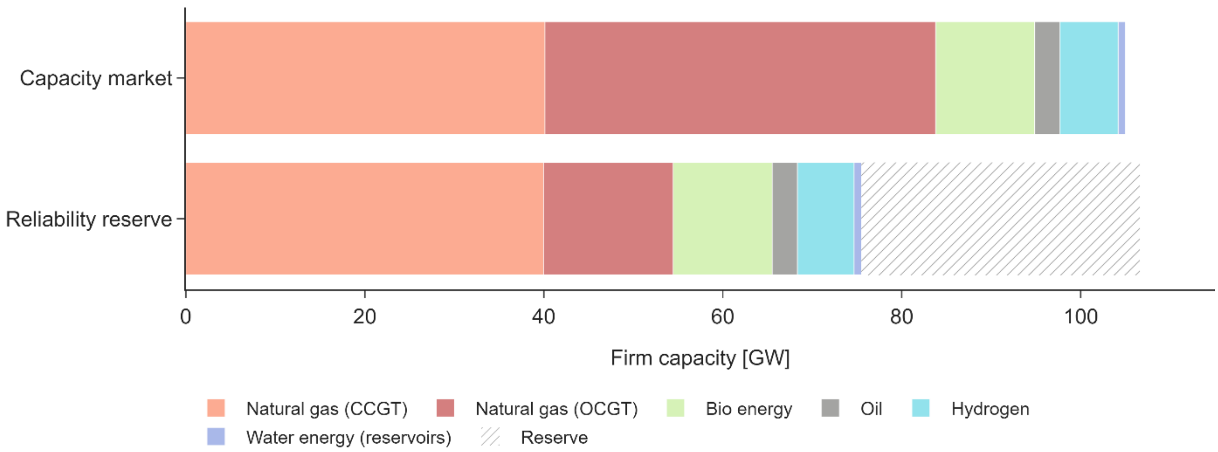

Figure 5: Comparison of installed secured capacity by energy source for the capacity market and the reliability reserve

Overall comparable total capacity. Both the capacity market and the reserve were dimensioned in the modelling in such a way that the demand for electricity is fully served in all modelled weather years. Depending on the weather year, not only the electricity generation of wind and solar power plants varies, but also the demand for electricity for heating buildings. This is also reflected in the comparable total installed power plant capacities in the model results of both scenarios. For the comparison of the scenarios, it was assumed that new constructions of comparatively low-cost gas turbines (OCGT) would be included in both the capacity market and the reliability reserve. In reality, however, existing plants could also be included, as is already the case with the existing capacity reserve.

7.4 Comparable energy supply costs in the short term

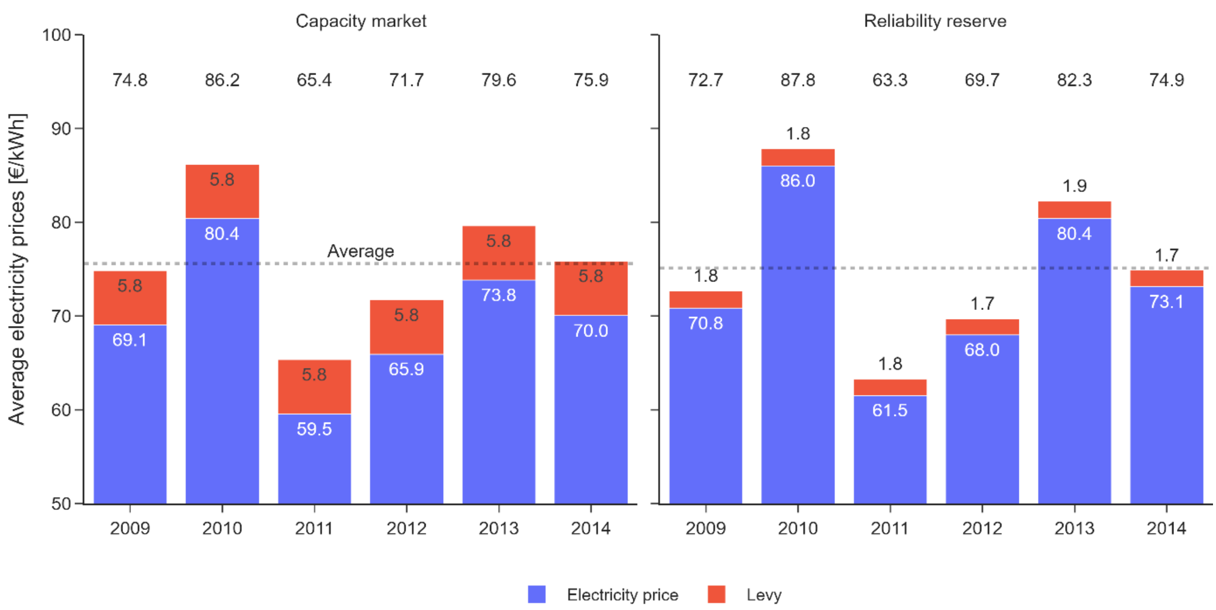

Figure 6: Comparison of the average wholesale electricity price and the resulting cost allocation for each policy option for the capacity market and reliability reserve in different weather years (2009-2014)

Comparison of average electricity prices. Figure 6 compares the average electricity prices of the various policy options for a capacity mechanism. This refers to the average wholesale prices and the allocated costs from the capacity mechanism per megawatt hour of electricity demanded. Other price components for end customers such as grid fees or levies are not taken into account. The absolute price levels depend primarily on factors such as the assumed fuel prices and should not be interpreted as a policy-relevant forecast for 2030 - also in view of the simplified model setting.

Higher cost allocation from the capacity market. In addition to the costs for the generation of electrical energy, the capacity market and reliability reserve also incur the costs for the respective capacity payments. The respective costs allocation is significantly higher in the capacity market, as all power plants receive a payment in the amount of the annuitized investment costs and annual fixed costs of the marginal power plant, which in the model is an open gas turbine. With the reliability reserve, only the power plants in the reserve receive a payment of this amount.

Higher electricity market prices in the case of the reliability reserve. In contrast, electricity prices are higher in the case of the reliability reserve, as it allows market prices of up to €500/MWh, while the centralised capacity market effectively caps market prices at a significantly lower level. These higher prices enable investments in power plants, storage facilities and flexibility on the wholesale market, as the marginal power plant or the marginal flexibility option can cover its fixed costs.

Comparable total costs. The total electricity costs hardly differ between the two market design options on average over several years. Initially, the capacity market performs slightly better at €75.58/MWh than the reliability reserve at €76.75/MWh. The greater the flexibility potential that is unlocked in the market design with the reliability reserve in the years after 2030, the better it is likely to perform compared to the capacity market. For example, the modelling does not yet take into account the potential in the areas of households, commerce, industrial cross-section technologies, self-generated building heating (e.g. heat pumps) and electromobility. Significant demand-side flexibility potential can still be tapped here in the future, particularly against the backdrop of advancing electrification and sector coupling.

7.5 Reliability reserve is very rarely activated

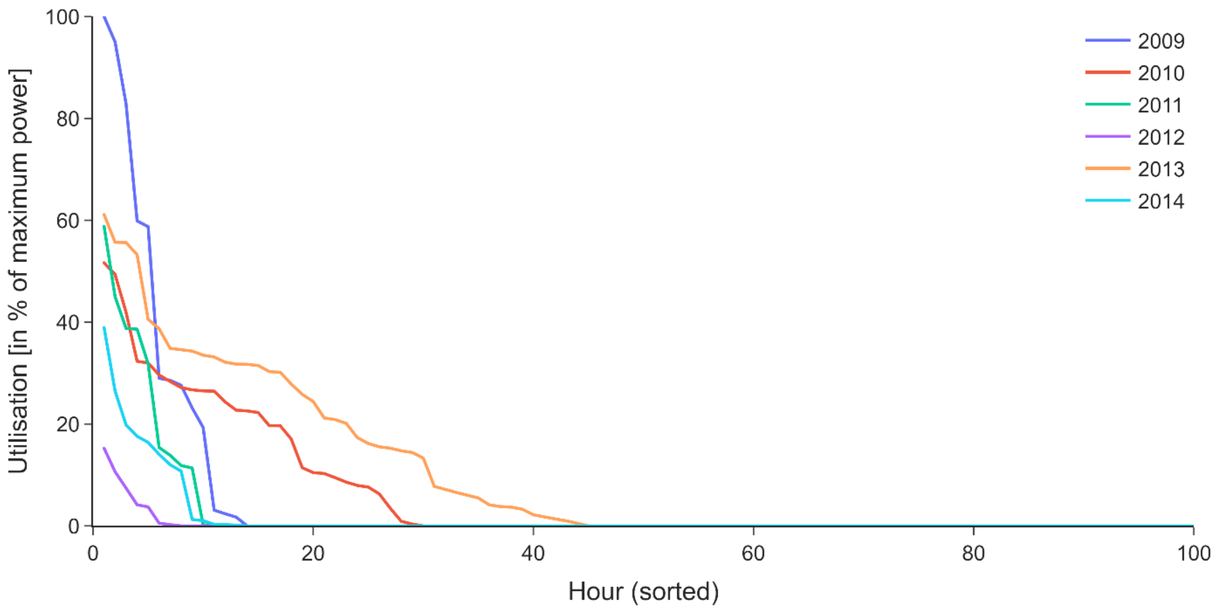

Figure 7: Operating hours of the reliability reserve in different weather years

Very rare use of the reserve. The modelled reliability reserve is only used for very few hours. Depending on the weather year, it is between 10 and 50 hours. And even within these few hours of use, the reserve is only utilised at more than half capacity in a few individual hours. In the six weather years included in the analysis, the reserve therefore only sets the electricity price for a maximum of 50 hours. (Figure 7). This also implies that the most important investments will not be made in the reliability reserve, but within the electricity market. The appendix illustrates how the reliability reserve helps to stabilise revenues from the electricity market and thus contributes to a more attractive investment environment compared to a simulation for a stylised energy-only market.

The dimensioning of each of the capacity mechanisms is a challenge. In view of the extremely rare activation of the reserve in only a few hours with very high output, it seems plausible that the reserve and the comprehensive capacity market could in reality be smaller than modelled here. Ultimately, a weather situation with cold temperatures and low wind and solar power generation – as observed on a December day in 2009 – leads to such a high remaining demand for electricity that the reserve must be dimensioned almost twice as large as would be necessary for all other 2190 days in the model. For example, a certain positive price elasticity of electricity demand in addition to the specifically modelled investments in demand-side flexibility could help to reduce the size of the reserve capacity. In the same way, the European electricity network not modelled here could help to reduce the reserve capacity to be held (cf. Roth and Schill 2023). Last, but not least, there may be further potential to negotiate additional contracts with large consumers to reduce their peak loads for the very few peak utilisation hours. Such uncertainties are a major challenge for regulatory authorities when determining the size of both a capacity market and a reliability reserve. In contrast to the comprehensive capacity market, the reliability reserve has the advantage that an adjustment of the design size does not directly affect supply and demand on the electricity market and therefore does not affect pricing. With the reliability reserve, the electricity market is therefore protected against the resulting regulatory uncertainties and the framework conditions for investments in the electricity market are thus strengthened.

8 Conclusion: Reliability reserve is a suitable and quickly realisable alternative to a capacity market

Consider demand flexibility in capacity mechanisms. A capacity mechanism for an electricity market increasingly based on wind and solar energy should be designed in such a way that the full incentives for the development of demand flexibility in the electricity market are ensured. The German government appears to be aware of this aspect, as it emphasises the important role of flexible demand in an electricity market characterised by renewable energies in its options paper on electricity market design. However, in view of the European experience with capacity mechanisms, which have only very rarely led to the promotion of demand flexibility in the past, it is questionable whether this can be achieved with the options currently being discussed by the BWMK.

Decentralised capacity mechanisms raise questions. In theory, decentralised mechanisms such as mandatory hedging on futures markets or the decentralised capacity market provide incentives for the activation of demand-side flexibility options. However, the practical feasibility and functionality of these decentralised mechanisms with regard to effectively ensuring a high level of security of supply appear questionable. The centralised capacity market and a reliability reserve remain more viable alternatives in the short term. However, these have different effects on demand-side and storage-side flexibilities.

Model calculations illustrate the flexibility advantages of the reliability reserve compared to a centralised capacity market. The model calculations illustrate this: Compared to the reliability reserve, a centralised capacity market leads to significantly less demand flexibility being unlocked. At the same time, both the reliability reserve and the capacity market appear suitable for ensuring security of supply.

The reliability reserve has further advantages. A reliability reserve could be implemented quickly, as there is already a lot of experience with the tendering and operation of existing reserves in Germany. Existing power plants that are already part of existing reserves or that will be decommissioned in the coming years for economic reasons could be transferred to the reliability reserve. Furthermore, a reliability reserve appears to be significantly more adaptable and less irreversible than the introduction of a centralised capacity market. This is particularly true as decisions on the size of the reserve do not have a direct impact on price trends and therefore the investment framework conditions for flexibility and generation capacity in the electricity market. A reliability reserve could therefore contribute to a significant strengthening of the investment environment in the market.

Important aspects of the design of the reliability reserve. When designing the reliability reserve, it must be ensured that the reserve power plants are not utilised even if the electricity prices are above their variable costs but below the trigger price for a longer period of time. There are three reasons that strengthen the credibility of the trigger price. Firstly, further investment in the energy system requires a credible investment environment, which would be severely weakened by a short-term adjustment. Secondly, the anchoring of the mechanism in the EU electricity market regulation promises that the approval of the EU Commission must be obtained before any adjustment is made. Thirdly, it can be assumed that, in combination with a phase-out of fossil-fuelled electricity generation, fossil-fuelled power plants in particular will be included in the reliability reserve. If these were to generate electricity too often and too early (i.e. at prices below €500/MWh), this would lead to increased greenhouse gas emissions in the electricity sector. This contradicts national and international climate policy goals. The credibility of the agreed trigger price could therefore be strengthened by anchoring it in national and international climate policy agreements. This could strengthen the investment framework in the electricity market. At the same time, the reliability reserve would strengthen the transition to renewable energies and flexibility options, as the power plants can be kept in reserve for emergencies.

Reliability reserve as a better alternative. Properly designed, a reliability reserve could be a better alternative to a capacity market. It guarantees the security of electricity production even in hours of low electricity generation from renewable energies. At the same time, increases in wholesale prices above €500/MWh are avoided without excessively limiting the market incentives to expand demand flexibility. This can create a market environment in which variations in the electricity price level are possible and security of supply is guaranteed at the same time. This also creates a learning environment for flexibility. At the same time, the more flexibility potential is unlocked, the lower the average electricity market prices will be in the long term.

Further research required. In this study, the potential advantages of a reliability reserve over other capacity mechanisms were discussed and illustrated both qualitatively and quantitatively. In view of the knowledge gaps that still exist, further studies would be desirable. These include, for example, more detailed analyses with numerical models for the specific parameterisation of the reserve. In addition, the expected interaction with the support of renewable electricity generation - which is also about to be reformed - is of interest. This also includes the interaction with decentralised options for sector coupling and prosumers who, for example, operate batteries, electric vehicles or heat pumps in a way that optimizes solar PV self-consumption. Last, but not least, further research into the European coordination of the design, procurement and operation of reliability reserves would be desirable.

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Annex: Reliability reserve strengthens investment framework in the electricity market

The discussion about capacity mechanisms is motivated by the fear that the energy-only market creates inadequate framework conditions for investments in security of supply. Against this background, it is of interest how capacity mechanisms affect the investment framework conditions. Framework conditions are particularly attractive for investors if revenues minus variable costs are stable.

Figure 8 shows how the contribution margin develops in the various market designs between the years, including a stylised energy-only market. In all market designs, the investment volume in the various generation and flexibility options was determined in a model run for the year 2010. This can be interpreted to mean that investors made competitive investments in this year with a full understanding of the supply and demand situation. Accordingly, it can also be seen that a gas turbine (OCGT) can generate its fixed costs exactly in all electricity market models this year. Full regulatory certainty was assumed. In particular, investors assume that even extreme price shocks in the energy-only market will not lead to any regulatory intervention in the market. Chapter 3 listed reasons that argue against the plausibility of this assumption. In this respect, the model run is intended more as a kind of hypothetical benchmark for comparing the electricity market models.

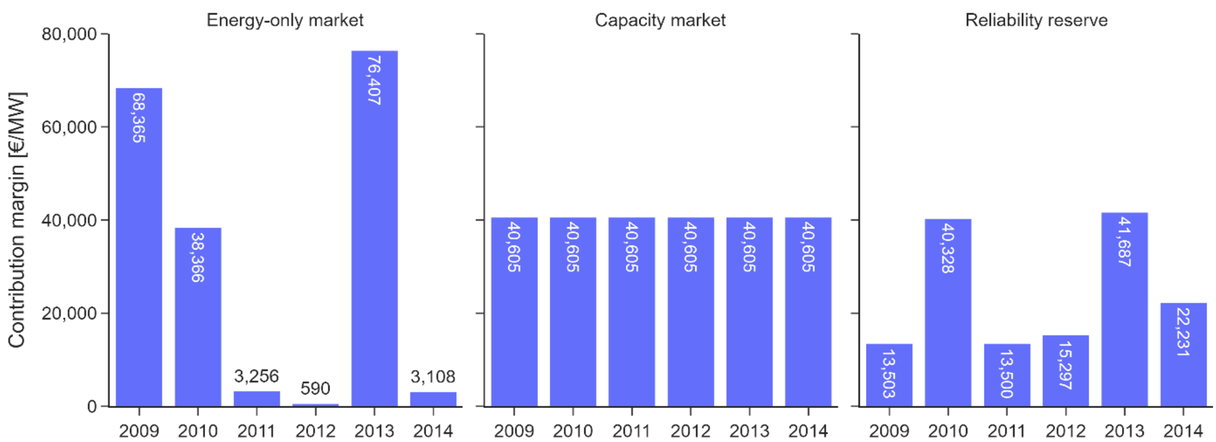

Figure 8: Contribution margins for gas turbines

The model comparison shows that there are years in the energy-only market in which operators of gas turbines can generate virtually no contribution margins, while other years have very high contribution margins. These fluctuations show the investment risk. In the capacity market, on the other hand, the long-term agreed capacity payments lead to stable contribution margins over the years. In the case of the reliability reserve, the contribution margins fluctuate only moderately between years. This illustrates how the reliability reserve leads to a stabilisation of the contribution margins that can be generated in the energy market.[24] This leads to a strengthening of the investment environment for generation capacity and flexibility in the electricity market. In addition, the regulatory certainty and futures markets listed in Chapters 3 and 4 will also strengthen the market.

[24] The investment decisions are based on a model run for the weather year 2010 and therefore do not necessarily lead to cost recovery for the energy-only market and the reliability reserve on average for the other weather years. This would require a simulation with investment decisions taking into account all weather years.