ACHIEVING GENERATION ADEQUACY WITHIN THE GERMAN POWER MARKET

A study on behalf of GE Power

14 NOVEMBER 2022

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Executive Summary

The phase out of existing power plants, increased variability of electricity generation from variable RES-E and a quickly increasing electricity demand are challenges to the German power system adequacy. One crucial element to secure generation adequacy in a fully decarbonised electricity system will be the sufficient availability of reliable **backup capacity** which can provide power in times of peak demand and/or low generation from renewables.

The objective of this study is to both show the urgent need for backup capacity as well as to carve out the main hurdles investors in backup capacity are currently facing alongside recommendations on how generation adequacy within the German power market can be achieved.

We conclude that the **urgently needed backup capacities** in Germany will largely consist of **thermal power plants** which can provide **capacity**, **flexibility** and (in the long-run) **carbon neutral** power generation. Estimates on the requirements of additional thermal power plant capacities in addition to batteries and Demand Side Management (DSM) vary between 14 to 42 GW until 2030/2035 and 26 to 88 GW until 2045/2050 under different scenarios of the future power system in Germany. With currently less than 4 GW of thermal capacity under construction, it is evident that a lot needs to be done to ensure the timely availability of urgently needed thermal power plant assets. While batteries and DSM can help to bridge shorter scarcity periods of several hours, backup power capacity is urgently needed to allow a reliable power supply when RES-E availability is low for several days or weeks in a row.

Currently, a highly uncertain market environment hinders investment decisions from being made. To reduce uncertainty, **regulators and decision makers need to provide clarity** on the following three aspects:

1. The participation **rules** in the future European and German power market.
2. The **remuneration** mechanism for flexible generation technologies.
3. The availability of **infrastructure** and **fuels.**

The current energy crisis has induced a number of debates regarding the future power market design in Europe and Germany. In particular, the questioning of the merit order principle and related fundamental reform of the European power market announced by the European Commission in September 2022 has created a high uncertainty around the rules that participants in the future German power market will have to follow. This makes well-informed investment decisions currently almost impossible. There must be clarity as quickly as possible on how the future power market design should look like. In particular, the following should be ensured:

- **A market mechanism with a functioning price signal needs to prevail**. The required volumes of backup capacities cannot be easily derived but depend on numerous developments in our energy system and beyond. State-based rigid volume planning may not always be able to provide an efficient amount of capacities. Theoretically, it is preferable to **allow market mechanisms to determine the needed volumes**. However, this requires a high degree of transparency in the market, acceptance of price peaks as well as clear responsibilities (there can't be free lunches i.e., for balancing responsible parties). Also, lead time of capacity build out may put the effectiveness of an energy only price signal in question. Therefore, transparent and liquid forward markets will be required to ensure a timely price signal. Sending price signals years in advance could also be achieved, for example, through state-mandated generation adequacy requirements for electric utilities like in some states in the US or for other balancing responsible parties.[1]

- **Technology agnosticism** is critical to allow technological innovations for development of most efficient future solutions. We will need a variety of technologies to ensure both security of supply and timely decarbonisation (i.e., SNG fuelled gas plants or natural gas with CCU/CCS).

- The **new support schemes for hydrogen power plants** (sprinter plants and combi plants) envisaged in the EEG 2023 are first steps to incentivise investments in dispatchable capacities that run on hydrogen. But many questions in regard to hydrogen supply and cost as well as flexibility during the fuel-switch from natural gas to hydrogen remain open and pose a risk to investors. Clear and transparent participation rules for the support schemes will allow for efficient market outcomes based on clear goals (climate, security of supply) and an adequate carbon price. In any case, they need to be designed carefully but quickly. They will need to be different from existing support schemes and reserve products for two particular reasons: First, different to existing reserve products (i.e., network reserve, capacity reserve), the hydrogen plants within the new support schemes will most likely not be kept outside the energy market but will be allowed to sell electricity and, thus, interfere with price formation. Second, different to existing support schemes for renewables, the new subsidies aim at dispatchable plants. As backup capacities on the energy market, they will aim at hours with low RES-E infeed - which are the hours where (unsupported) generation/flexibility sources like hydrogen plants, DSM, imports, pumped storages and batteries need to cover their costs. Thus, the new schemes will interfere with competition in the energy market and advantage subsidised capacity significantly. Furthermore, it needs to be clear that any proposal should address the risk from volatile fuel prices (i.e., for green hydrogen), a risk that Wind on/offshore and PV plants do not face.

- **Locational scarcity needs to be visible**. Locational signals are important to reveal scarcity of local generation or transmission capacity in certain regions (i.e., in the South of Germany). Alternative bidding zone configurations, as currently discussed and analysed in ACER's bidding zone review, should be taken into consideration as well as other options like locational network tariffs or locational signals as part of the auction design.

- At the same time, it needs to be ensured **that bidding zones stay large enough to provide liquid markets** that enables hedging strategies. Furthermore, investment decisions won't be

1 However, lessons learnt from other electricity markets cannot be simply transferred to the German case, but should be rather seen as case studies for further evaluation. Changes in the functioning of a market need to fit within the overall market design which can differ quite significantly between electricity markets.

made under constant uncertainty about bidding zone reconfigurations. Once decided upon, the new bidding zones should be kept stable to allow investors to plan.

Decision makers need to provide clarity on **the envisaged remuneration mechanism for backup capacity** as soon as possible. One guiding principle should be that **all services** provided by backup capacity are paid for which means fair remuneration for (a) power generation, (b) capacity availability and (c) ancillary services.

- Backup capacity will generate electricity only during a limited number of hours. Prices must not be distorted (i.e., via highly debated price caps) but need to **allow for sufficient rents**. This means that price peaks need to be accepted. Furthermore, there must be clarity as soon as possible on how the deep reforms of the electricity system targeting the merit order principle announced by the European Commission should look like. The so far rather broad concepts described in the European Commission's Non-Paper from end of October 2022 including CfDs for inframarginal technologies or the subsidy scheme mechanism at EU level inspired by the Iberian model do not allow for any planning.

- The availability of dependable and flexible capacity is important to compensate for the variable RES generation and should be remunerated. The **design and formation of capacity remuneration elements must be clear**. They can either be organised by the state/regulator in the form of highly standardised capacity products or be built up via the market in form of "insurance" products. Ex-ante none of the approaches is systematically preferable – market-based insurance products are more flexible in terms of volume, product definition and pricing structure whereas standardised products are much more transparent. For insurance products to play a role, there must be a credible consequence (penalty) for balancing responsible parties if generation and load are not balanced. There can't be a free lunch (i.e., in form of state-based rescue schemes). Otherwise, no one would invest in such insurance products. Regardless of which approach is chosen, it is extremely important to send price signals years in advance to sufficiently support investment in new generation capacity, through liquid and transparent forward prices. A middle ground between relying on insurance products without government oversight and a centralized capacity market could be establishing state-mandated generation adequacy requirements for electric utilities or balancing responsible parties ("BRP") that create multi-year capacity procurement obligations. This would incentivise bilateral contracts for generation that provide renumeration for backup capacity, which could be uneconomic to build based on energy market revenue alone. While in an energy only market the idea is to incentivise BRPs to invest into capacity via the (credible) "threat" of the high energy price in scarce situations (and each BRP then "translates" the threat/risk into an individual back-up capacity procurement strategy[2]) the state-mandated procurement obligations already determine the amount of capacity an individual BRP has to procure. The benefit of the state-mandated procurement is that it is more transparent and the targeted capacity level is likely to be reached, the drawback is a much more

[2] The BRP or utility can decide how to procure the required back up capacity: it can invest into generation itself, procure options with a fixed option price (EUR/MW) and an ex ante fixed strike price (EUR/MWh) from other back-up capacity holders or can buy PPAs with a guaranteed profile (in that case the PPA seller has to back up the profile with his own assets and "smears" the capacity costs as part of the PPA price in EUR/MWh).

complex system to be established and monitored[3]. Both options allow the market to decide which backup resources are most economically efficient to be procured. However, the state-mandated obligation route would require a fundamental different market design setup in Germany and Europe (i.e., regional utilities pool or single buyer model) and/or complex rules to determine the efficient level of obligation for BRPs.[4]

- **Ancillary services are key to secure the grid stability and need to be fairly remunerated**. Foreseeable and fair payments in form of market-based payments (i.e., for frequency control) or regulated prices (i.e., reactive power for voltage control) can make a difference when making investment decisions. If new investments into instantaneous reserve products ("rotating masses") are required from a system perspective this "service" should be compensated.[5]

Lean and streamlined regulation must ensure **that the availability of all needed infrastructures in electricity and hydrogen generation, and transmission** are synchronised. Approval and permitting procedures must be clear and fast. Furthermore, the sufficient provision of fuels needs a clear and reliable certification system of climate-neutral fuels and the possibility to enter long-term commitments. Also, the access to capital markets needs to be clear for all market participants. Dedicated single buyer models like the German Hint.Co as intermediary absorbing parts of the volume risks are promising and could also lower the certification risk significantly. Hint.Co should be executed quickly, clarifying missing details around the scheme as quickly as possible. Furthermore, it should be established as a long-term measure to ensure investment planning. Uncertainties around EU Taxonomy need to be clarified sooner and should be aligned to fuel availability.

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3 The level of obligation has to be set for each BRP, rules for forecasting, rules for changing of customers to other BRPs and also "capacity credits" have to be defined to certain capacity types that qualify to fulfill the obligations.

4 In theory, the optimal level of obligation results in an efficient balance of "generation adequacy" and "cost efficiency" for the whole system taking into account uncertainty of future developments. For further details see p. 38

5 It can be argued that "rotating masses" come automatically with any turbine (and cannot be separated from the generation investment). While this is true once a turbine plant has been built, it can make a difference during the investment decision, i.e., when there are options with rotating masses (i.e., involving a turbine) and without rotating masses (i.e., PV, battery).

Generation adequacy at risk

Germany's goal of climate neutrality by 2045 places high demands on the energy system of the future. The energy transition towards decarbonisation will lead to an accelerated electrification of sectors such as mobility, heat and industry. This will drastically increase the need for electricity. According to the most recent grid development plan (*Netzentwicklungsplan 2037/2045*) from the German transmission system operators (TSOs) the **gross electricity demand will at least double** until 2045, from 530 TWh in 2020 to 1,080-1,300 TWh depending on the assumed degree of electrification.[6] The vast majority of the demand will be provided by renewable energy resources which will **massively increase the variability of the generated electricity.** Most renewable energy sources are not dispatchable. Generation in times of low wind and sun will be limited.

Increasing pressure on the German power system adequacy

Increasing demand for electricity in combination with variable electricity generation puts high pressure on the power **system adequacy** in Germany which is the ability of the power system to supply the demand at any given time. Decision makers need to ensure that system adequacy prevails in the future decarbonised and decentralised power system. This must be done by maintaining both **transmission** (i.e., the ability to manage the electricity flow resulting from the location of both consumption and generation) and **generation adequacy** (i.e., the ability to match generation and consumption). Grid expansion as well as additional generation capacities are urgently needed.

Already today black- and brownouts cannot be fully ruled out anymore

While additional generation capacities are urgently needed to cope with the increasing power demand Germany has agreed to phase out of both nuclear (initially by the end of 2022, now slightly postponed to 15 April 2023) and lignite and hard coal (by 2038 at the latest). This has already reduced in particular the guaranteed generation capacity, i.e., the generation that is reliably available for supplying the load, quite significantly and will further severe the generation adequacy in the upcoming years (**Figure 1**). **Already today the security of supply in Germany cannot be fully guaranteed by national generation capacities anymore**. In 2020, German TSOs identified a capacity gap for 2022 of between 1.5 GW (without mandated coal phase out) and 7.2 GW (with mandated coal phase out) and stated that Germany would become increasingly reliant on imports from neighbouring countries in times of low renewable utilisation.[7] Some degree of reliance on neighbours within the EU can be acceptable to benefit from efficiency gains of the internal market. However, this must be done in close coordination and needs to account for balancing effects, network constraints. It should address more extreme situations like a cold winter in Europe and/or a low availability hydro or nuclear plants in Europe. With other countries facing similar challenges, less surplus power will be available in Europe to be imported to Germany at times of high demand and low RES output.

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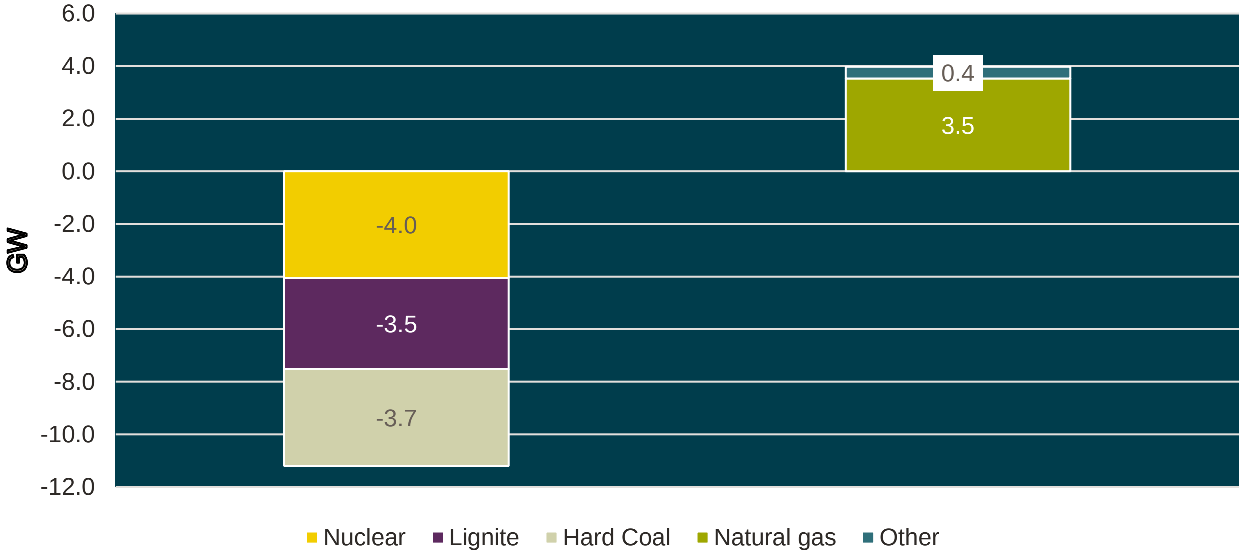
6 Netzentwicklungsplan 2037/2045 (2023)

7 Bericht der deutschen Übertragungsnetzbetreiber zur Leistungsbilanz 2018-2022 (2020)

Figure 1 Expected decommissioning of and newly build flexible power plants by 2025



Source: Frontier Economics based on BNetzA (2022): Veröffentlichungen Zu- und Rückbau Stand 05.2022
Note: "Other" entail storages, batteries and oil

In recent months the situation has become even worse: The Russian war on the Ukraine, the drought in the summer, low river levels and the unavailability of a vast share of the French nuclear fleet has resulted in a severe Energy crisis with scarcity on the power and gas markets. By allowing coal and lignite plants from the reserves to come temporarily back onto the market and by slightly postponing the closure of the last three nuclear plants the German government has put measures into place to reduce tension on the power market.[8] Still, following the most recent power system stress test, German TSOs cannot rule out hourly crisis situations in the electricity system during the winter 2022/2023 anymore.[9] They urge to make use of all possibilities to increase electricity generation and transport capacities. If all these measures are not sufficient, exports will need to be restricted and/or large consumers temporarily be shut down as a last resort to maintain grid security. The threat of brown- or even blackouts has reached an alarming level.

Controllable and flexible generation capacity is key to ensure generation adequacy

To increase the security of supply the German generation adequacy must be enhanced by

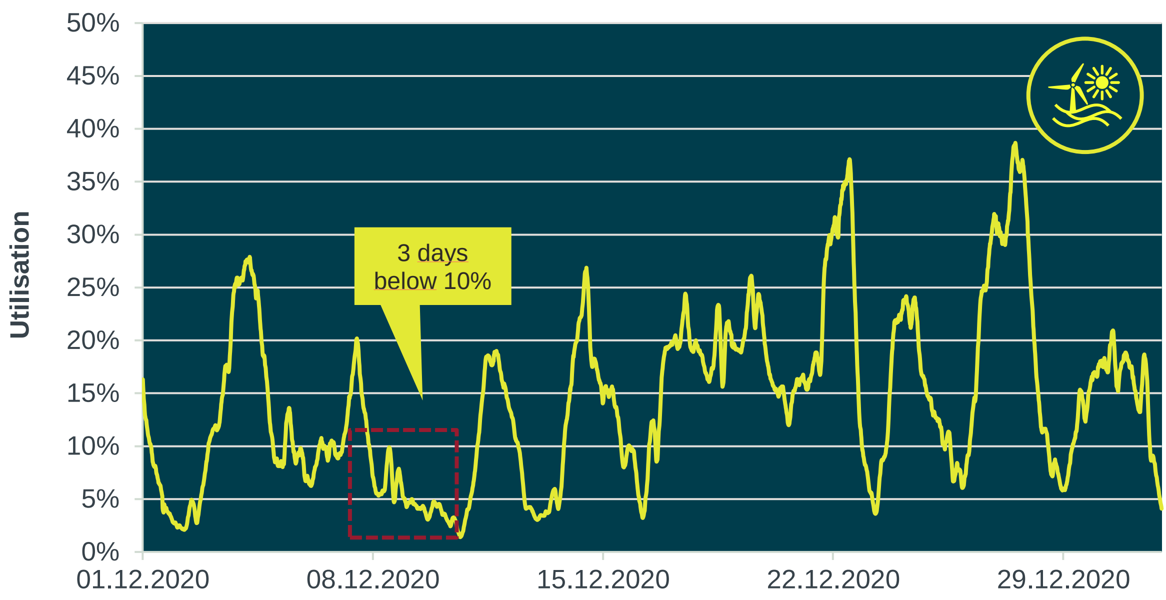
- Increasing RES generation capacity;
- Increasing the overall flexibility of both demand and supply; and
- Adding controllable and flexible generation capacity.

8 Ersatzkraftwerkebereithaltungsgesetz (2022)

9 Sonderanalysen Winter 2022/2023 (2022)

Power from renewable generation will present the key component of the future decarbonised power system in Germany. Thus, RES capacities need to be increased significantly which is reflected in the most recent amendment of the German Renewable Energy Sources Act (EEG 2023) which entails higher expansion targets for Wind and Photovoltaics (PV). However, the increased generation **variability** in the power system due to higher RES shares will make it necessary to further provide the power system with sufficient flexible resources, such as energy storage units or demand side management tools. Flexible resources can adjust both demand and supply quickly, which helps to increase the system flexibility. However, the cost of flexible resources is generally high. Many DSM options or storages (i.e., batteries or pumped hydro storages) can only bridge a few hours of supply scarcity by using the stored energy to cover demand in low wind/low sun hours. However, weather data shows that on a national or European level there can be periods of low supply from wind farms or PV lasting many days and even weeks as for instance in Germany in December 2020 (**Figure 2**). That is why **additional controllable and flexible generation capacity is needed** which can provide in times of peak demand and maintain a level of generation adequacy which is required in an industrialised country where industry and citizens expect a high availability of electricity supply.

Figure 2 Utilisation of PV & wind power capacities in Germany, December 2020



Source: Frontier Economics based on Bundesnetzagentur | SMARD.de

The mandated phase outs of both nuclear and coal leaves thermal power plants as the most credible technology to provide backup capacity in the mid- and long-run. This is also stated in the coalition agreement of the current German government according to which natural gas will be indispensable for a transitional period until the large-scale availability of climate-neutral gases like green hydrogen.[10]

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10 Koalitionsvertrag (2021), p.59

In the following sections we will first elaborate on the estimated amounts of additional thermal power plants needed in the medium and long-run to ensure both the security of supply and decarbonisation goals. We then continue with assembling the several hurdles investors in thermal power plants face in the currently uncertain market environment, before developing recommendation on how to improve key aspects to foster investments in urgently needed backup capacity.

Additional thermal capacities needed in the medium and long-term

Clean, thermal power plants will stay indispensable in a decarbonised power system to ensure generation adequacy. There are several studies that have modelled the cost-efficient amount of additional thermal capacities needed in the mid- and long-run. They all assume a widely decarbonised power system by 2030/2035 and a fully decarbonised energy system by 2045/2050, but differ in terms of further assumptions like the degree of electrification in sectors like mobility, heat and industry, assumptions on costs of RES, hydrogen, energy storage systems, DSM and thermal plants, interconnector capacities to exchange power with neighbouring countries as well as political interventions like the coal phase out, intended independence of neighbouring countries etc. Estimates do thus differ quite significantly but present the best available assumption on the needed thermal capacities.

Medium term: Up to 42 GW of additional thermal capacities needed until 2030

Until 2030/2035 the different studies estimate required additional thermal capacity to be installed in Germany between 14-42 GW (**Figure 3).**

Agora (2022) models a climate-neutral electricity market for Germany by 2035 for which 14 GW of gas-fired power plants are needed by 2030 and 29 GW by 2035 in addition to today's available capacity of 32 GW.[11] GE (2022) modelling results indicate that the need for new thermal power plants in Germany by 2030 could reach 39 GW in a scenario with high demand growth driven by electrification. EWI (2021), assuming a coal phase out by 2038, estimates between 15 and 19 GW of additional gas plants in 2030, depending on the profitability and phase out of lignite plants.[12] BCG (2021) assumes the coal phase out to be completed already by 2030 as envisaged in the coalition agreement. This would mean an earlier closure of 17 GW lignite and hard coal capacity compared to the phase out by 2038. In addition, BCG concludes an increased need for guaranteed capacity of 101 GW in total by 2030. This results in an additional need for 42 GW of gas powered plants by 2030.[13]

With the most recent agreement between the German Ministry for Economic Affairs and Climate Action (BMWK) and RWE to close RWE's last three lignite plants (3 GW) already by 2030 the earlier coal phase out by 2030 has been initiated already.[14] It is thus much more likely that the needed amount of guaranteed capacity in form of thermal power plant in the medium term will lie in the upper bound (i.e., between 26-42 GW) than in the lower bound (i.e., 14-25 GW) of the above estimates.

11 Agora (2022): Klimaneutrales Stromsystem 2035

12 EWI (2021): dena-Leitstudie Aufbruch Klimaneutralität, Gutachterbericht, Oktober 2021

13 BCG (2021): Klimapfade 2.0

14 BMWK (2022): Pressemitteilung zum beschleunigten Kohleausstieg 2030 im Rheinischen Revier

Long term: Up to 88 GW of additional thermal capacities needed until 2045

In the long-run even more thermal capacity additions are needed to ensure the goal of full decarbonisation (**Figure 3**). Estimates vary between 26 GW (Fraunhofer's (2021) hydrogen scenario[15]) and 88 GW (Dena's (2018) electrification scenario[16]). All other studies line up in between. The large range shows the high uncertainty about the future electricity system. In any case, large thermal generation capacity additions will be needed.

Needed investments in replacement or retrofitting of existing gas-fuelled plants

Besides investments in capacity additions, large investments need to be made to either replace or retrofit the existing gas-fuelled power plant fleet. Today's installed capacity of 32 GW is old, on average 33 years old already.[17] These investments need to be taken into consideration in addition to the new thermal capacities.

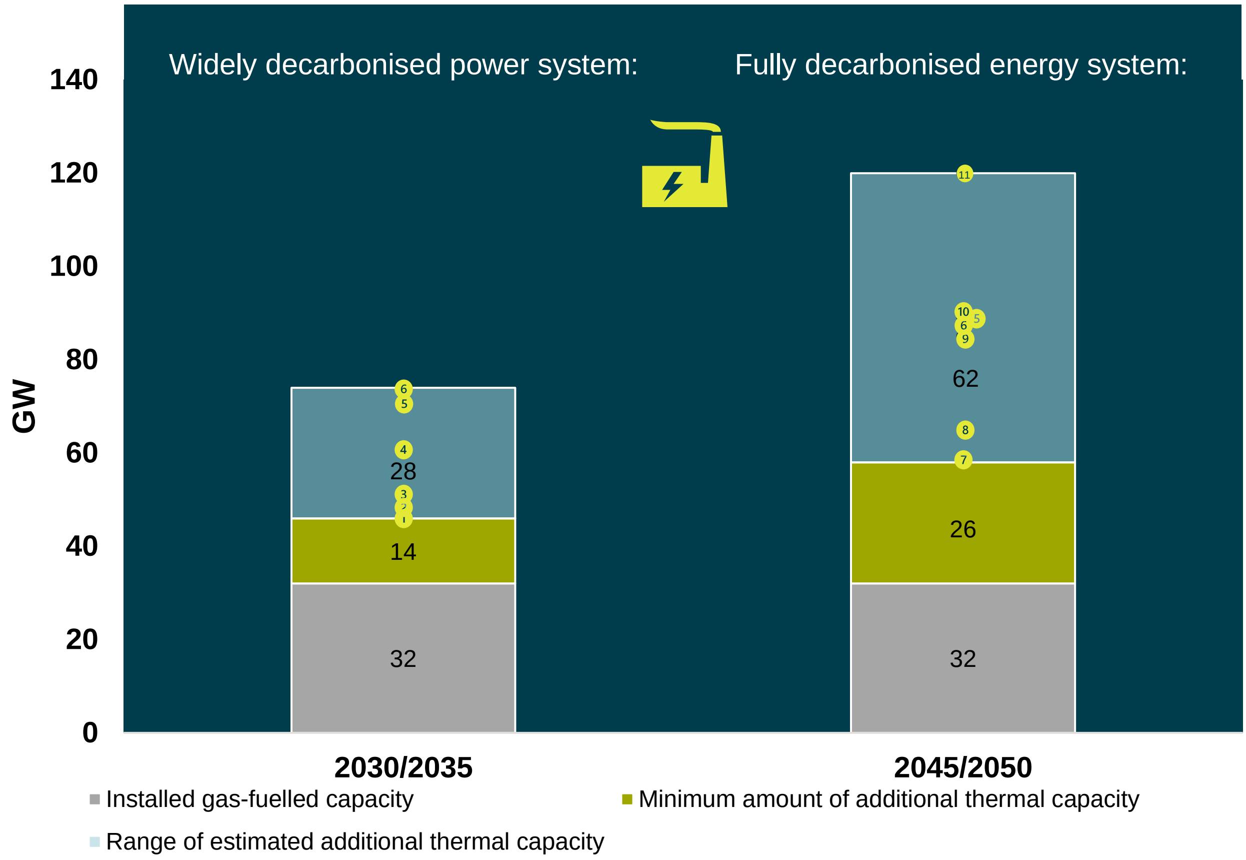
The framework conditions must be set in a way that enable a longstanding profitable operation of thermal generation capacity of up to 120 GW. A huge task for decision makers.

15 Frauenhofer ISI (2021): Langfristszenarien für die Transformation des Energiesystems in Deutschland

16 Dena (2018): Leitstudie - Integrierte Energiewende

17 BNetzA (2022): Kraftwerksliste Stand 31.05.2022

Figure 3 Thermal generation capacity by 2030/2035 and 2045/2050



Source: Frontier Economics based on data from quoted studies and BNetzA

Uncertain market environment hampers investment decisions

Getting the capacities timely into the market is a challenging endeavour which can only be ensured within a suitable power market design that facilitates investment decisions into thermal power plants. To ensure the right level of investments, regulation needs to be adequate, clear and sound – if not, there will not be proper business cases to invest in thermal backup capacities leaving the security of supply in Germany at risk. The current investment environment is highly uncertain, unstable and leaves investors with hesitation. In 2021 only 3.6 GW of gas-fuelled power plants projects (planned or under construction) were reported to the Federal Network Agency[18] (**Figure 1**). A lot needs to be done to ensure the necessary investments for maintaining security of electricity supply.

In particular, the following **key aspects** induce uncertainty that hamper investment decisions:

1. **Remuneration**:
Which revenue streams are envisaged for thermal power plants that will run at lower capacity factors to cover costs?

2. **Long-term market risks**:
How will prices evolve and which possibilities to hedge are available?

3. **Availability of fuels:**
Will there be sufficient fuels (natural gas, climate-neutral gases) available to operate the plant?

4. **Lengthy approval processes**:
How long will it take to get the permission to build the plant? Will the needed infrastructure (power, gas / H_2) be operational on time?

5. **Policy risks for plant owners:**
Are there going to be further policies that will devaluate dispatchable generation assets? If so, will there be any form of compensation?

18 Bundesnetzagentur (2022): Monitoringbericht 2021

In the following sub-chapters, we will explain in detail the challenges investors in thermal power plants face and elaborate on possible options to reduce investment risks.

Remuneration: Little certainty on revenue streams for backup capacity

Thermal power plants are urgently needed as **controllable and flexible generation capacities** which can provide in times of peak demand and maintain a level of generation adequacy. At the same time the number of hours they will be needed will decrease with an increasing share of power from renewable energy sources. However, investments in thermal power plants are capital intensive and need to generate sufficient income from reliable revenue streams to cover not only the short run marginal costs (SRMC) but also the investment and fixed costs for operation and maintenance (O&M).

In general, there are **three possible revenue streams** for thermal power plants:

Energy Price Mechanisms:
Revenues from selling power on the electricity markets (in €/MWh)

Capacity Price Mechanisms:
Revenues for the pure availability of generation capacity (in €/MW)

Price Mechanisms for ancillary services:
Revenues for providing grid stability services (in €/MWh and/or €/MW)

In the German power system revenues are predominantly generated from sales of generated electricity on the power markets (so-called Energy only market (EoM)). Capacity price or remuneration mechanisms (CRM) are limited to tools of the strategic reserve, the so-called "safety belt" of the EoM to ensure generation adequacy. Plants that are part of the strategic reserve cannot participate in the EoM (so-called marketing ban (*Vermarktungsverbot*)) and are only used in emergency situations with very scarce electricity supply. This means that the strategic reserve does not interfere with the price setting mechanism on the EoM. Furthermore, plants operating on the EoM can participate in the auctions of the balancing reserve markets to provide grid stability services. Here, elements of both energy pricing and capacity pricing can be found.

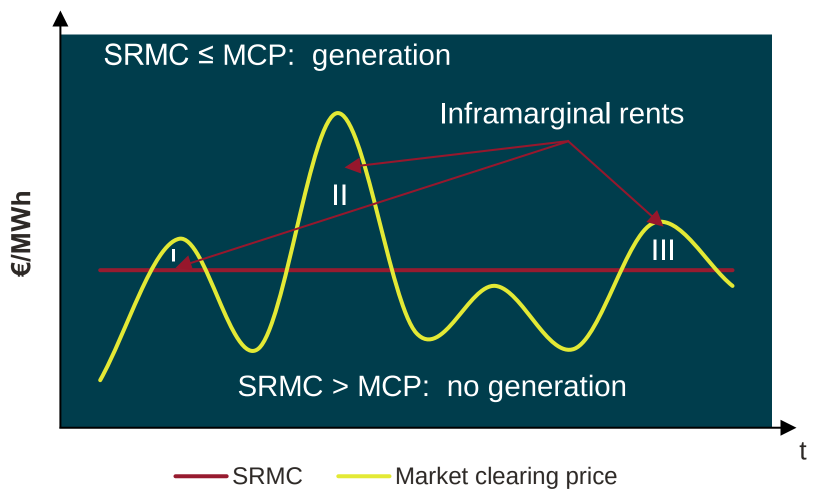
In all three cases, there is uncertainty about how the respective revenue options in Germany may evolve in the upcoming years. This makes the planning of business cases for new thermal power plants difficult.

In the following we will describe the uncertainty in the respective cases and discuss three possible approaches to ensure sufficient and stable revenue streams.

Energy Pricing Mechanism: The questioning of the merit order principle and skimming of inframarginal rents

In an EoM, producers bid their SRMC into the day ahead market. If the market clearing price (MCP) is equal or above the SRMC the bid is successful, and the plant generates power to supply the market. The plant then receives the market clearing price in €/MWh. To cover fixed costs and fixed O&M the plant needs to make margins over time which occur when the market clearing price is above the SRMC. These margins are called inframarginal rents (**Figure 4**).

Figure 4 Stylised presentation of revenues in an EoM



Source: Frontier Economics
Note: For simplicity SRMCs are assumed constant

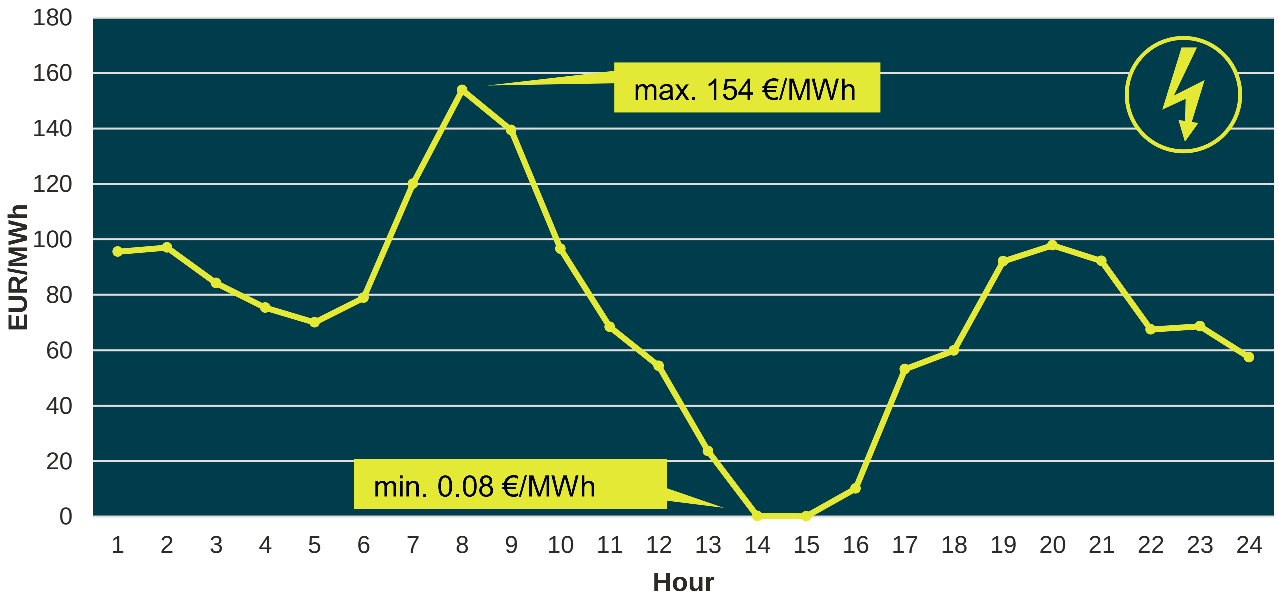
Furthermore, future and forward markets allow power producers to hedge energy price risks by selling future generation at a fixed price. This can also be done in form of a purchase agreement (PPA) which is a contract that defines the commercial terms between the seller and the buyer of electricity and may last up to 20 years.

Sky rocking gas prices following the Russian war on the Ukraine in combination with the drought in the summer, low river levels and the unavailability of a vast share of the French nuclear fleet have resulted in unprecedented price levels on the European electricity markets induced by price setting gas power plants. In the following a number of emergency interventions have been proposed/implemented to either reduce the power prices by decoupling the power market from gas prices (i.e., the Iberian subsidies for input costs of fossil fuel-fired power plants) or to skim ex-post the inframarginal rents from generators (i.e., the EU and DE revenue cap). All models have severe flaws (i.e., administrative hurdles, inducing cash flow issues for power producers, distorting market outcomes, over-utilisation of gas plants, loss of price signals, etc..) and should if at all be seen as temporary measures to avoid hardships and supporting industries to survive. However, even this short-term insecurity about inframarginal rents may results in investors delaying planned investments in thermal power capacities.

Much more severe are the related discussions about fundamental reforms of the European power market announced by the President of the European Commission, Ursula von der Leyen, in her State of the Union speech on 14 September 2022 according to which the current electricity market design – based on merit order – is not doing justice to consumers anymore and will undergo a deep and comprehensive reform.[19] Details, however, are entirely unclear. The immature Greek proposal of a permanent split of the day ahead market into a mandatory pool for low-variable cost technologies (wind, solar, hydro, nuclear and fossil cogeneration) and a separate market for the rest further increases insecurity of the future power market design.

The questioning of the merit order principle and thus the possibility to benefit from inframarginal rents is hampering investments in backup capacities severely. In a world with decreasing hours in which thermal dispatchable plants are needed, investors are dependable on sufficient rents in those few hours where they operate. This makes a functioning price mechanism signalling scarcity indispensable. The EoM has proven to provide these necessary prices. It should be kept as the key instrument to foster investments in efficient amounts of generation capacities. The supply/ demand balance within a bidding zone in a certain "market time unit" is reflected by the price level. The situation of supply/demand, i.e., whether a bidding zone is "long" with electricity (showing lower prices) or "short" (reflected via high price levels) often changes even within a day as can be seen when looking at daily price shapes in Germany (**Figure 5**). Therefore granular, energy price signals are important to "deliver the message" on the actual degree of scarcity to market participants.

Figure 5 Power Prices in the German/Luxemburgish spot market on 23.09.2021



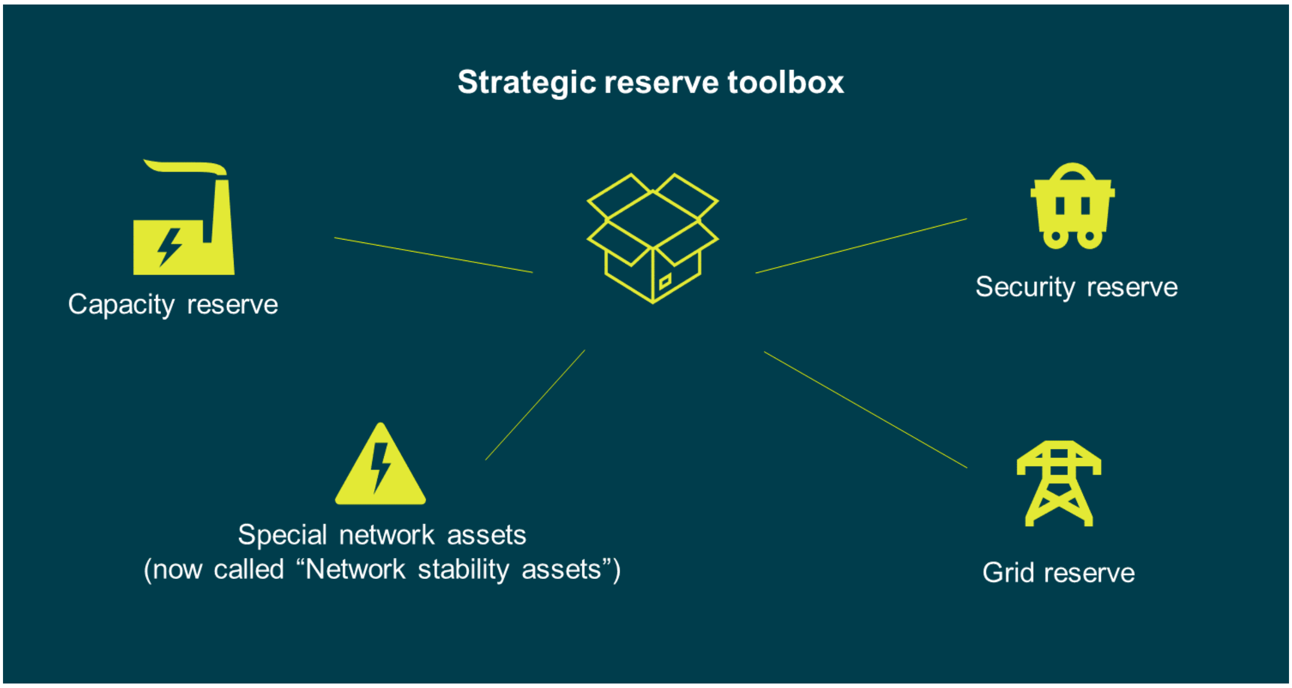
Source: Frontier Economics based on data from Energate
Note: The graph shows prices for EPEX SPOT DE-LU (Phelix)

[19] 2022 State of the Union Address by President von der Leyen

Capacity Pricing Mechanisms: None of the strategic reserve tools attractive for newly built thermal assets

Within CRM payments are made for the pure availability of generation capacity in €/MW. Within the German power market design, CRMs are mainly designed as a form of strategic reserve product which are tools to ensure generation adequacy when the EoM is unable to clear and are explicitly designed not to interfere with competition on the EoM. They are also called the “safety belt” of the EoM.

Figure 6 The strategic reserve toolbox involving plants based on CRM



Source: Frontier Economics

There are currently four main reserve tools that entail power plants that are based on CRM (**Figure 6**).[20] However, most of them do not present a reliable option for plannable revenues for newly installed thermal capacity. While some are not open for thermal power plants at all (security reserve for lignite plants), others entail mainly old plants that are temporarily put into a reserve due to their system relevance (Grid reserve) or consisted of one-off auctions (Network stability assets). Only the capacity reserve represents to a certain extend an option for which new thermal plants could apply for. However, the secured revenue streams are limited to two years – and thus not sufficiently long for a business case. More details on the tools can be found in **Table 1.**

Further CRM exist within the EoM in form of bilateral agreements. They serve as insurances for example for balancing responsible parties who need to ensure a balance supply and demand within

[20] The planned temporary reserve for the remaining nuclear plants until April 2023 has been abolished. Plants will now be kept on the market until 15 April 2023.

their area also when generation from RES (i.e., contracted via PPAs) is not available. The relevance of these products is difficult to evaluate due to the non-transparent nature of bilateral agreements. However, the increase of European Energy Exchange (EEX) trading volume for German power options by 60 per cent in 2020 is an indication of an increased need for hedging tools in a volatile market environment.[21] However, it can be expected that the relevance is increasing considering the increasing share of RES PPAs. For these products to prevail it is essential that there is no "free lunch/free riding" for power consumers in scarce situations. Otherwise, there won't be any incentives for balancing responsible parties to invest or contract backup power.

It can be concluded that current regulated strategic reserve tools have limited attractiveness for investments in new thermal capacities whereas the relevance of private insurance CRM products can hardly be evaluated given the missing transparency in bilateral agreements.

Table 1 The key features of the tools of the strategic reserve based on CRM

Capacity reserve	▪ Safety belt if day ahead market does not clear (hence, after the market) ▪ Power plants, storages or DSM in the reserve are not active on the EoM anymore ("Vermarktungsverbot") and only produce at the orders of the TSO. ▪ The selection process is a biennial competitive bidding process by the TSOs and included 2 GWs of capacity in the past periods (which was not completely filled). ▪ Capacity payment in €/MW/a (63k €/MW/a in last auction for 2022-2024)
Grid reserve ("Winter reserve")	▪ Systemically relevant generating capacities (plants and storages) that should have been shut down (temporarily or finally) are used to ensure enough potential for redispatch activities (after market) ▪ Capacity is selected by TSOs and put into the reserve for 2 years. ▪ Especially important in winter months (where there is a high volume of wind in the north of Germany and low volumes of sun in the south) → also called "winter reserve" and mainly holds power plants in Bayern and Baden-Württemberg (currently 8 GW). ▪ Selected power plants cannot sell their electricity on the market during this time ("Vermarktungsverbot") ▪ The Substitute Powerplant Maintenance Act (*Ersatzkraftwerkebereithaltungsgesetz*) will enable hard coal plants in the reserve to temporarily return to the EoM (until March 2024) to reduce the dependency on gas ▪ Capacity payment in €/MW/a
Network stability assets	▪ This stability tool was first allocated in 2019 and is required to secure supply in times of sudden failures of other production facilities (curative redispatch potential for Southern Germany) ▪ The contracted plants or storages must be able to get to their full load production within 30 minutes and must be able to keep this for 38 hours. ▪ In total 1.2 GW have been auctioned split into twelve packets of each 100 MW (could be bid for by solely or in bundles)

21 EEX Group Annual Report 2020 (2021)

		▪ Assets in the scheme for 10 years (until 2032); no further auctioning planned ▪ Capacity payment in €/MW/a
	Security reserve	▪ Reserve entailing lignite power plants that have left the EoM based on the mandated coal phase out. Used to meet demand if all other safety belts fail to do so ▪ Temporary scheme of in total 2.7 GW (8 lignite plants) to facilitate the coal phase out ▪ The Substitute Powerplant Maintenance Act (*Ersatzkraftwerke-bereithaltungsgesetz*) will enable the plants in the reserve to temporarily return to the EoM (until March 2024) to reduce the dependency on gas

Source: Frontier Economics *based on EnWG and BNetzA*

Payments for ancillary services: Important additional revenue streams

The third possible revenue stream for dispatchable power plants consists of payments for the provision of ancillary services to maintain system reliability and stability. Ancillary services ensure that the power grid is operated in a safe and reliable manner. Providers are typically reimbursed for these services through ancillary service prices and payments. The importance of ancillary services markets is growing as power grids evolve with more variable RES and demand sources. The associated revenues could become a major factor in making/breaking the overall business case for investment in flexible capacity capable to provide such system services.

In Germany these consists of **balancing power markets** which allow the TSOs to procure control reserve products via daily auctions (balancing capacity and balancing energy). The current control reserve products are Frequency Containment Reserve (FCR), Frequency Restoration Reserve with automatic activation (aFRR) and the Frequency Restoration Reserve with manual activation (mFRR). Precondition for providing these services is a pre-qualification procedure. If qualified, plants can opt to participate in the auctions and get remunerated for capacity (reservation) and energy delivery if called.

The **provision of voltage control capability** can be part of the network connection agreement with the TSO. If applicable, capacity and certain delivery for reactive power is "for free" for TSOs. Compensation for additional reactive power is typically limited to 2 EUR/MVArh. Fair remuneration for these services should be ensured given that connection requirements induce larger generators to be installed and thus additional capital expenditures (CAPEX) and/or higher losses for plant investors.

Black start capability is the ability of a power plant to ramp up from a shutdown state independently of the power grid. It is particularly important in the event of a widespread power blackout to bring the power grid back into operation. Black start capability is compensated based on bilateral agreements.

Further services like "**rotating masses**" to compensate for a short-term drop in supply before activation of the control reserve products ("Momentanreserve") are under debate but not yet installed.

Several proposals exist (i.e., by TSO Amprion).[22] If implemented, the additional remuneration could help to make investments in thermal power plants much more attractive.[23]

Ancillary services to ensure system reliability and stability will become much more important in an electricity system with less reliable supply sources. Thermal power plants, as reactive fast ramping sources, are ideal to provide these services. However, not all these services are paid for fairly. Fair remuneration can turn ancillary services into a much more important revenue stream for newly installed thermal power plants.

Price Risk: Possible bidding zone splits, available hedging options not clear

As shown in the previous section power prices play a central role for the economic viability of generation assets in the current power market system. Uncertainty around the development of prices is in the nature of functioning markets which change constantly and often in a hardly predictable way. Still, investors need a certain degree of predictability on price influencing general market conditions. Furthermore, instruments are needed that can reduce the price risk. Price risks are controllable from investors' perspective if they can be hedged.

Despite the risk of a fundamental reform of the European power market which might results in a totally different (unpredictable) market design, there is further uncertainty on the general market conditions induced by the ongoing pan-European bidding zone review. Bidding zones are areas in Europe in which a single (wholesale) electricity market price applies. The European Union Agency for the Cooperation of Energy Regulators (ACER) is obliged to assess the efficiency of the bidding zone configuration every three years. If inefficiencies are revealed, ACER can request the relevant TSOs to launch a review of an existing bidding zone configuration.

Inefficiencies result, when locational scarcity (in form of transmission or local generation capacity) is not sufficiently signalled (i.e., via prices). If signals are missing, then no sufficient investments are induced to reduce the respective scarcity. The current debate around splitting the German national bidding zone has recently heated up mainly due to three aspects:

- Under the pressure of high power prices in Germany, the Northern German states have asked for a price zone split hoping for lower power prices in the North spots bidding zone split. The North of Germany is "long" with generation thanks to the short distances to harbours and excellent wind conditions (and also accepting disadvantages of wind farms).

- German neighbouring countries such as Poland or Netherlands were suffering from so-called "Loop flows". These loop flows are congesting the neighbouring countries' transmission networks due to power flows from northern German generation via the neighbouring country and back into

[22] Amprion (2022) : Systemmarkt Konzeptpapier

[23] Due to the growing but still limited market size, the revenues from ancillary services will not be the dominant income source for most new power plants. However, the revenues from ancillary services can bring an investment "over the hurdle rate".

the south of Germany (and before the German and Austria bidding zone was split up also back into Austria). Regulators have been reacting with the German/Austrian price zone split and also by the introduction of the so-called “70% rule” as well as introducing “flow based market coupling” for day ahead trading.

- Germany currently faces more than 2 bln. EUR congestion costs per year.[24] Costs arise due payments/compensation to curtailed wind farms and redispatched power plants which is necessary to solve congestions in the national transmission grid (it also includes costs for capacity payments to the network reserve which is contracted to ensure redispatch potential).

This means, that under the current German market design there are no locational signals within Germany, that could

  - Show to TSOs where network scarcity lies and which could make TSO invest into more power lines,
  - Make new or existing power consumers “move” closer to cheap generation, or
  - Attract new generation to the areas in Southern Germany where generation balance is scarce.

However, looking deeper into this topic, it becomes clearer that a lot of further practicalities and complexities will need to be taken into account:

- The TSOs already “know” where the congestion is and are more than willed to invest. This is also accepted by the regulator who even supports the TSOs in messaging to local stakeholders who often delay network projects as people close to the new network infrastructure are typically negatively affected (environment/skyline is impacted, local population fears magnetic field etc) while not benefitting much from the network infrastructure (the well-known effect related to many infrastructures in Germany the so-called NIMBY effect: “NIMBY- Not in my backyard”). This means the locational price signal to the TSO is not really providing incremental benefit.

- Also, the price signal to consumers will not easily change behaviour. Existing consumers are unlikely to move to other areas. Some new industry will need local experts or will use certain by-products which is limiting their flexibility to “move”. However, some new industry/processes might be more flexible and will be influenced by the signal (i.e., some new electrolysers). So, in total, the positive impact from the locational signal might be rather limited in many cases when it comes to investment decisions, but could provide some incentives in dispatching/consumption decision and for some new consumers.

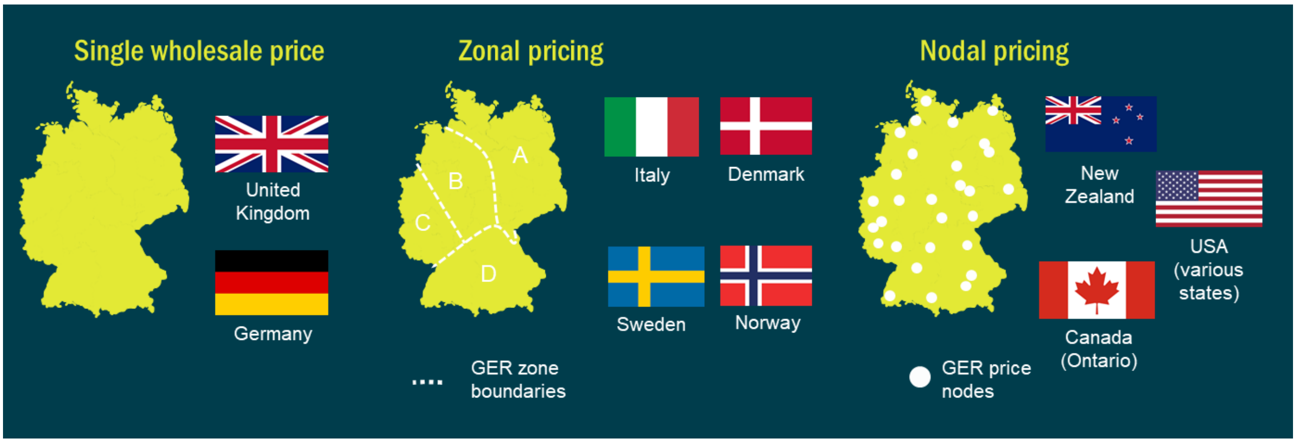
- The locational price signal to new generation and local flexibilities will be the most relevant. However, higher fuel costs or worse wind conditions would need to be compensated from the higher local power prices to compensate for the “move”. Also fuel access would need to be guaranteed so that a price signal can actually have an impact on investor’s behaviour. Again, the

[24] Bundesnetzagentur (2022): Netzengpassmanagement – Viertes Quartal 2021

price signal can influence not only allocation of a generation asset but also dispatching (which on the long run also might influence the locational choice).

The discussion in Germany is currently focussed on various forms of the so-called "bidding zone" split. In theory, various other forms of locational signalling exist, such as the so-called "nodal pricing" (which is an extreme form of small bidding zones applied in the US) but also instruments like regionally differentiated network tariffs for generators or consumers could be discussed (and many other instruments). Comparing market designs across the globe, various forms of locational signalling are applied (**Figure 7**). Again, there is no "one size fits all solution" for the best design – country specifics and regulatory framework need to be considered. What is clear, however, is that aspects like risk mitigation/hedging options, liquidity and local market power etc have to be considered when designing the best solution.

Figure 7 Illustration of locational price choice in Germany



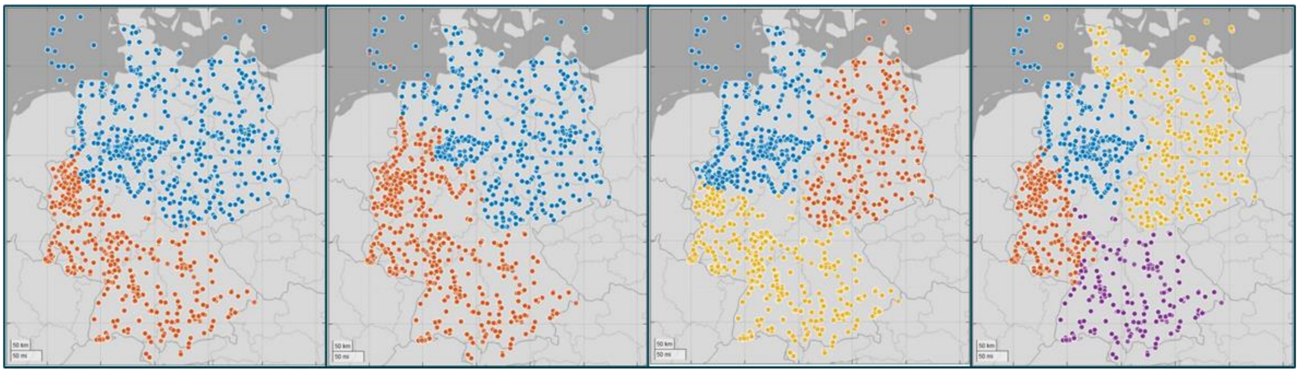
Source: Frontier Economics

Note: Example maps are illustrative, and do not reflect actual network zones or nodes.

The discussion on a new bidding zone design for Germany has recently restarted. ACER has published various options which will be discussed in coming months. The ACER list of alternative bidding zone configurations to be considered for the current bidding zone review entails four alternative bidding zone configurations for Germany and Luxembourg who currently form together one bidding zone (**Figure 8**): two different splits in two bidding zones, one split in three bidding zones, and one split in four bidding zones. This shows the strong focus on Germany in this review, considering that for all the other countries that are mentioned only one alternative bidding zone is listed. Furthermore, ACER has requested TSOs to undergo LMP simulations.[25] Both the short-term split into zones and mid- to long-term split into a nodal system seem possible.

[25] ACER: Bidding zone review

Figure 8 Possible bidding zone reconfigurations for Germany



Source: ACER (2022): List of alternative bidding zone to be considered in the bidding zone review

Smaller bidding zones tend to reveal local scarcity much more effectively. However, they result in less liquid markets due to the lower number of market participants. Hedging options and possibilities to enter long-term contracts with consumers become smaller which further aggravates the investor's options to control for price risks.

In summary it can be stated that locational price signals are important market features to reveal scarcity: At the same time, it needs to be made sure that bidding zones and/or regional market aggregation points or trading hubs are established to provide liquid markets that enable hedging strategies. The alternative bidding zone configuration for Germany should be taken into consideration and implemented quickly where appropriate. With respect to our study on investment incentives, it is important to understand that investment decisions won't be made under constant uncertainty about bidding zone reconfigurations. Once decided upon, the new bidding zones should be kept stable for an appropriate amount of time (and not be under review every 3 years) to allow investors to plan.

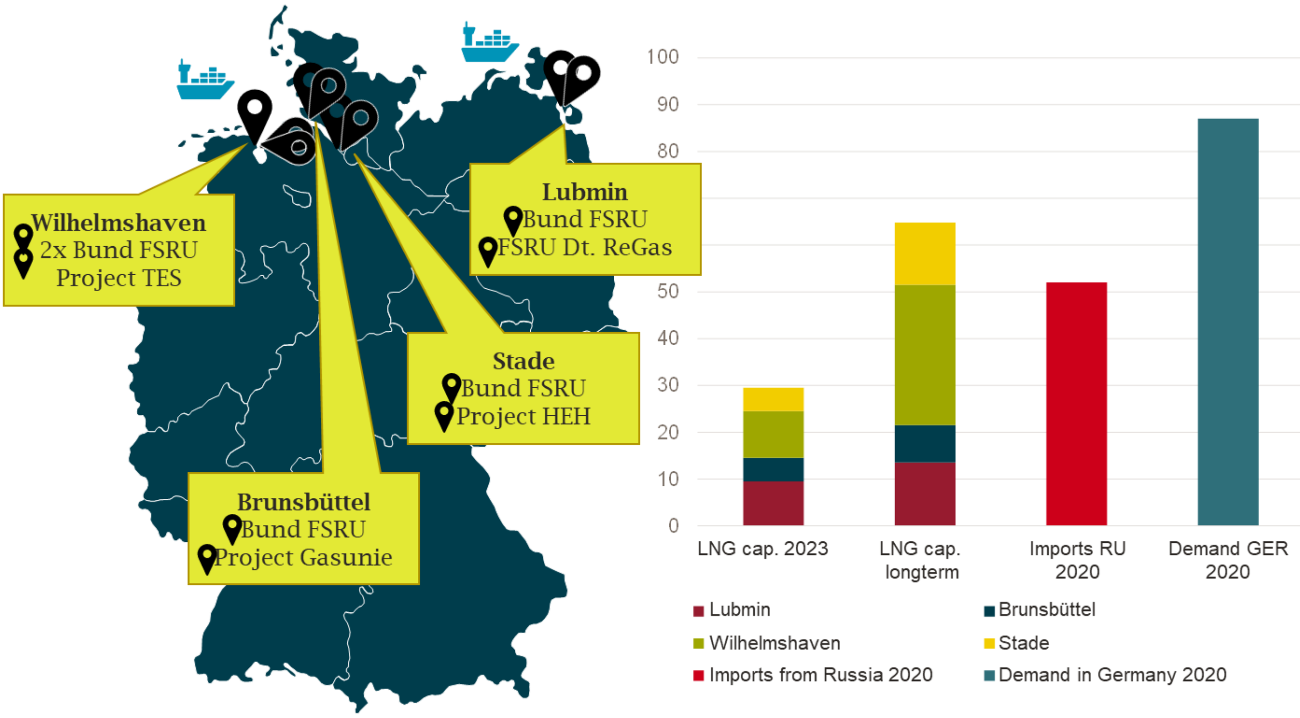
Fuels: Availability of inputs uncertain

The availability of required (fuel) inputs is essential for the operation of a power plant. For thermal power plants this means in particular the long-term and guaranteed availability of the required and backup fuels as well as access to the infrastructure.

Until the large-scale availability of climate-neutral gases like green hydrogen, thermal gas-fired power plants will tend to operate on natural gas. The current energy crisis has revealed how insecure the access to natural gas can be under a not well diversified supplier portfolio, relying mainly on Russian gas. Since the start of the crisis, the German government has made great efforts to diversify its import sources, contracting more gas via pipelines from Norway and accelerating the construction of LNG terminals. The new LNG terminals will enable the replacement of a large share of the Russian imports already by 2023. In the long run it will be possible to replace Russian pipeline gas fully via LNG gas (**Figure 9**) This means that Germany is on track to reinstate a secure access to natural gas.

Nevertheless, the current crisis should be a warning to never again depend on one external source as much as it was the case with Russian gas.

Figure 9 New LNG terminals can fully replace Russian gas imports in the long-term



Source: Frontier Economics based on data from the project companies

In the long-run, thermal gas or hydrogen fired power plants will need to switch to climate-neutral gases to meet climate targets. Many uncertainties remain about the sufficient availability of these fuels:

- First, up to now it is unclear which gases will qualify as climate-neutral in Europe. The EU as well as Germany both focus on green hydrogen in their hydrogen strategies which is produced of electricity from renewables. The future relevance of alternatives like synthetic natural gas (SNG), natural gas and carbon capture and utilisation or storage (CCU/CCS), or other hydrogen colours (i.e., turquoise, blue+CCU/CCS or from nuclear power) remains unclear.

- Second, the infrastructure for the large-scale production and delivery of green hydrogen needs to be build first. This means huge investments in electrolysers and transmission options like pipelines, ships etc. Green hydrogen will need to be either produced locally or imported from regions with high RES penetration. In both cases this means massive investments either within the EU or outside. These investments will only be made if investors can rely on a long-term commitment to the "fuel", i.e., the use of blue hydrogen or certain forms of biomethane.

- Third, investments in intra-EU electrolyser capacity will not take place as long as the exact conditions for hydrogen to qualify as green in the EU are still not clear. However, clear and pragmatic definitions on "what is qualified as green gas" need to be developed taking into account green gases “Made in Europe” but also imported gases. Accordingly, certification schemes need to be in place. The ongoing debates about the sustainability criteria for green hydrogen needs in the context of the approval of the delegated act under the 2018 Renewable Energy Directive (so-called RED II) induce high uncertainty for investors (and unnecessarily high production costs for green hydrogen).

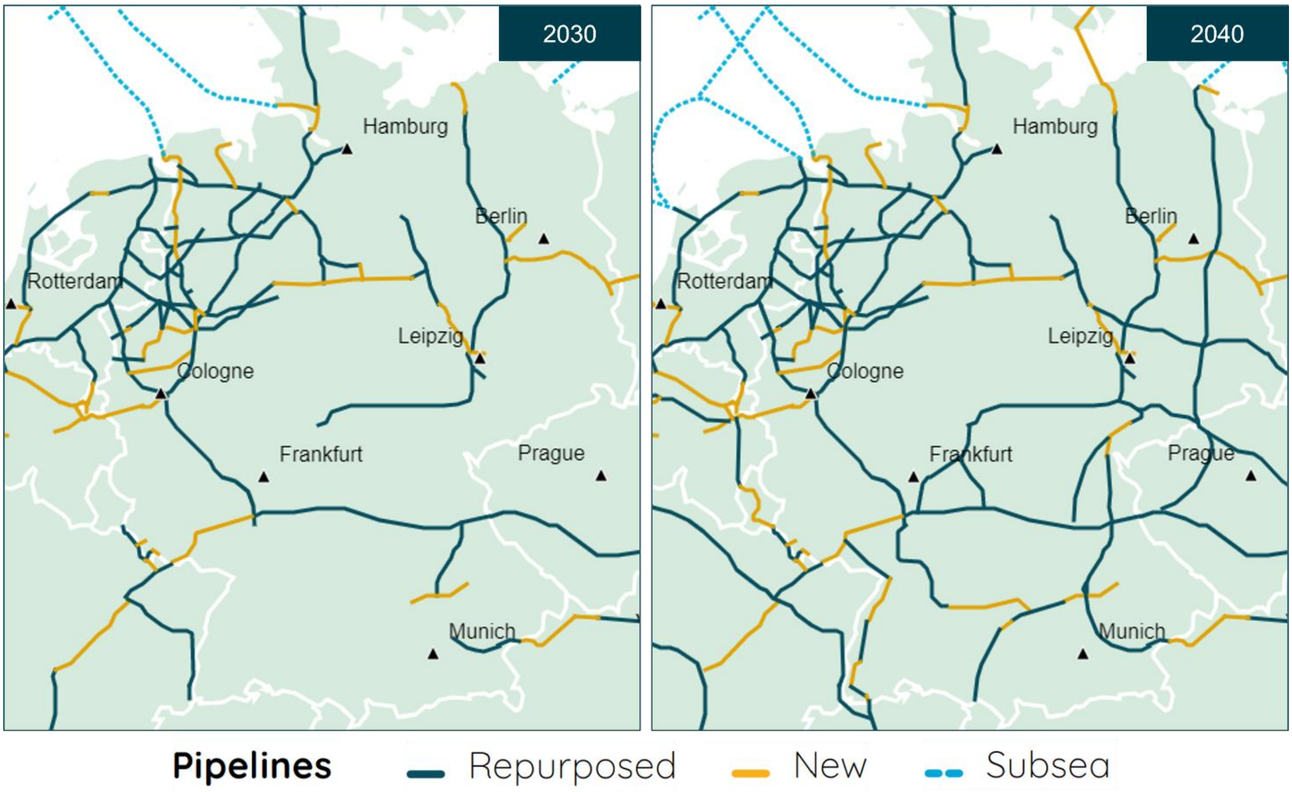
- Fourth, green hydrogen will need a sophisticated distribution network involving pipelines, train infrastructure and trucks. The European hydrogen backbone initiative, involving group of thirty-one energy infrastructure operators,[26] probably presents the best view on a future hydrogen pipeline network in Europe. According to the newest version of the backbone in particular large parts of southern Germany, where thermal power capacities are most urgently needed, will not be linked to the network before 2040 (**Figure 10**). The debate on how to bring “clean fuel” to the Southern parts of Germany will be crucial which can be seen from the so-called “stress test” performed by the German TSOs in the context of the extension of the run time for nuclear power plants for several months in reaction to the high power prices. A certification scheme for biomethane (fed into the gas grid somewhere in Germany) is currently discussed as one solution.

- Fifth, investors in thermal plant capacities need options to enter long-term contracts for fuel delivery. In the case of green hydrogen these do not exist yet, given that the infrastructure still needs to be build. Initiatives like Hint.Co[27] are promising but need to be further specified and installed first.

[26] The European Hydrogen Backbone (EHB) initiative: Partners

[27] Hydrogen Intermediary Network Company: Intermediary/Single buyer of the German funding project H2 Global for energy carriers based on green hydrogen produced in non-EU countries: Green Ammonia, Green Methanol and Sustainable Aviation Fuel

Figure 10 The European Hydrogen Backbone in Germany by 2030 and 2040



Source: The European Hydrogen Backbone (EHB) initiative

In sum, it must be stated that in particular the secured access of climate-neutral gases, like green hydrogen, cannot be guaranteed at this point in time, making investment decisions in thermal power plants very difficult. Furthermore, in the medium term, greater certainty of the availability (volume and price) of natural gas in Germany are necessary to support investment decisions.

Approval processes: Lengthy procedures slow down investments

Approval procedures are another important aspect for investors. Quick and reliable procedures help to realise projects in controllable generation capacity. This does also apply to the needed RES, the power grid and H_2 infrastructure expansions.

Unfortunately, Germany's approval processes in energy infrastructure have proven to be lengthy and are hampering investment decisions. Most recent examples are the wind onshore and biomass auctions in October 2022. Only 42% of the wind onshore volumes were tendered, for the biomass volumes it was only 1/3.[28] One reason for the low demand for the auction volumes is seen in permit issues and long-lasting approval procedures. The planning and approval process for wind onshore

28 Erneuerbare Energien von Gentner (13.10.2022): Wind- und Bioausschreibungen grandios unterzeichnet

projects for example takes on average 4 to 5 years.[29] For grid expansion projects approval processes can take even longer. The period between planning and the grid being operational can exceed 10 years.

With the Easter Package, the German energy law was comprehensively amended. In particular, the EnWG, EEG and WindSeeG have undergone extensive changes. The amendments entail also changes to simplify the approval procedures for wind onshore plants and electricity grids by removing barriers and streamlining procedures.[30] However, the fact that one barrier is still that the approval procedures are mainly paper-based shows quite bluntly how slow and inefficient approval procedures in Germany are.

The political efforts to fasten approval procedures of RES and grid expansion are important. The same focus should be put on streamlining approval procedures for thermal power generation. With a construction period of four to seven years they need even faster procedures to become operational as quickly as possible. Climate protection and security of supply must be given more weight in the approval procedures of thermal power plants, while accelerating and improving the approval procedures where possible. Short-term blackout or brownout costs can easily reach billions of Euros: In its European Resource Adequacy Assessment ENTSO-E uses Value of Lost Load ("VOLL") assumptions of 3,000 EUR/MWh to 15,000 EUR/MWh – if we apply a daily power consumption in Germany of about 1,5 TWh/a, one single day of nationwide black out would cost between 4 and 20 bln EUR (note that regional brownouts would be more likely to happen in a scarcity situation than a nationwide black out).[31] Further social costs arise from risks to lives or incremental costs in case of longer term (regional) supply interruptions or if a low level of supply security "scares" away certain industries – which can be energy intense but also digital industry like data centres who rely on a secure power supply (that's why they often have installed backup power devices on site that protect them for a limited time period) .

The unprecedented fast-track procedure for the construction and operation of a connecting pipeline for the planned LNG terminal in Wilhelmshaven has shown how quickly procedures can be if necessary. The procedure was approved in less than 4 months (the project also benefitted from previous site developments on which could be built on).[32] Authorities need to be adequately staffed with qualified experts, digitalisation can also help as do more simplified legislation and procedures. The costs of "delayed" approval are hard to quantify, but from the analysis shown above the significant need for investment shows that security of supply will be at stake.

29 Bundesverband WindEnergie: Planung von Windenergieanlagen

30 BMWK (06.04.2022): Overview of the Easter Package

31 European Resource Adequacy Assessment 2021 – Annex 5 – Country Comments (azureedge.net)

32 FAZ (19.08.2022): Neue Pipeline für LNG-Terminal Wilhelmshaven ist zugelassen

Policy risk: Devaluation of plant assets

Long history of policies devaluating dispatchable plants

During the last 30 years owners of dispatchable power generation plants have experienced significant devaluations of their assets driven by various implemented policies. For some compensations were given, for others not.

First, the **promotion of renewable energy sources** has enabled RES entering the power markets, reducing the full load hours of existing dispatchable plants. It started in 1991 with the German Electricity Feed-in Act (*Stromeinspeisungsgesetz*) which obliged grid operators to feed-in power from RES and was followed by the German Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz*) in 2000 which has continuously promoted RES via subsidies and quotas. Even if from a climate policy perspective those policies were reasonable it must not be neglected that they have devaluated existing plants for which no compensations have been given. The same applies to an increasingly tighter CO2 pricing regime (although most plants also benefitted from receiving emission allowances ("EUA") for free in first years of the EU Emissions Trading System (EU ETS)).

Second, **mandated phase outs of nuclear, lignite and coal** have prohibited certain business models entirely, reducing the value of the plants to a minimum:

- In the case of the **nuclear phase out** the back and forth of the planned ending of nuclear power in Germany have left power producers with high uncertainty over the last 20 years: The first agreement to end nuclear power from 2002 (in form of an Amendment of the Atomic Energy Act) under the Red-Green Government (Schröder Cabinet I) was modified in 2010 under the conservative-liberal Government (Merkel Cabinet II) by extending the operating lives of some German nuclear plants. Then in 2011, after the Fukushima nuclear disaster, a three-month moratorium for the oldest nuclear plants was followed by an agreement to a gradual nuclear phase out by 2022. Power plant operators subsequently had to file lawsuits in order to receive compensation payments. Only in December 2016, five years after the moratorium and agreement to phase out by 2022, the Federal Constitutional Court awarded the affected energy companies the right to compensation for damages due to the premature nuclear phase out. Now in 2022, again an extension of the lifetime of some plants is debated by some political parties like the liberals (FDP). The operation of nuclear power plants in Germany over the last 10 years has been hardly plannable, compensations needed to be fought for.

- Lessons learnt from the nuclear phase out were considered in the process to agree on the **coal phase out**: With the German Act to end power generation from coal *(Kohleverstromungs-beendigungsgesetz)* it was agreed in 2020 to phase out of coal by 2038 at the latest, paying compensation to lignite plant operators based on agreed settlements while compensation for hard coal plants will be given based on auctions. With already envisaged compensation payments the coal phase out has been managed significantly better than the nuclear phase out. Still, also in the case several uncertainties induced by the mandated phase out have remained: In the case of lignite an ongoing in-depth investigation by the European Commission to analyse whether compensation payments are in line with EU State aid rules have prevented compensations to be paid. In the case of hard coal, the auctions are designed in a way that will leave some plant operators without any compensation.

It should not be neglected that several policies have also increased the value of dispatchable plants. This applies in particular to policies aiming to increase electrification which drives up the demand for power. All in all, however, it needs to be stated that the long history of devaluation of dispatchable plant assets in combination with unclarity on compensation has reduced the trust of plant operators significantly.

Going forward this means that any new policy affecting the business models of generation capacity need to be clear and sound, leaving no room for speculation and entailing legally solid compensation schemes if business models are forbidden. With respect to thermal power plants the new envisaged support schemes for hydrogen plants need to be clarified and communicated effectively to avoid “attentism” among investors in (unsupported) thermal plants but also in DSM and energy storages who will be most likely all devaluated by supported H_2 and biomass power plant capacities through lower full load hours. Also, it must be clear how decision makers will act in case the provision of climate-neutral gases cannot be guaranteed, disabling thermal power plants to operate.

New envisaged support schemes for H_2 power plants could result in attentism towards new (unsupported) investments in thermal power capacities

As part of the amendment of the EEG 2023 two new support schemes for H_2-ready power plants are envisaged:

- Subsidy auctions for so-called **sprinter plants with H_2-ready gas turbines.** Auction volumes will be gradually increased from 800 MW in 2023 to 1,400 MW in 2026. In sum, 4 GW of plants are going to be subsidised.

- Subsidy auctions for so-called **H_2 combi plants** which consist of a combination of electrolysers and H_2-ready gas turbines must be capable to feed-in electricity. Auction volumes will be gradually increased from 400 MW in 2023 to 1,000 MW of installed capacity in 2028. In sum 4.4 GW of plants are going to be subsidised.

Separate regulations ("Verordnungsermächtigung") will define details on how the schemes will be implemented exactly.

With these new schemes the German government tries to incentivise investments in the urgently needed thermal power plants. At first sight, this seems an appropriate approach. However, it must be noted, that these new schemes, even if details are still to be defined, will be different than other support schemes for two particular reasons which make investments in unsupported thermal power plants much more difficult:

- Different to many existing capacity reserve products these **plants will most likely not be kept out of the EoM**. The existing German reserve products (capacity reserve, grid reserve and network stability assets etc.) have deliberately been separated from the energy market and are not allowed to participate in the market while receiving capacity remuneration. This has been done to achieve state aid approval from the EU and to avoid interfering with competition in the generation sector. In this manner those plants receiving capacity remuneration do not interfere with the merit order and do not affect the full load hours of unsupported dispatchable power plants in the EoM. If the new supported H_2 plants are allowed to participate in the EoM they will devaluate existing or planned unsupported investments.

- Also, existing RES-E subsidies have interfered with the energy market and devalued existing plants, including combined heat and power (CHP) plants by reducing the hours they operate and/or their rents. However, the remaining backup capacities, having higher SRMC than RES-E, mostly aim at hours with low RES-E infeed. This means that existing dispatchable plants in the market are less influenced by adding more RES-E (of similar kind and profile) given that they operate in different hours of the year. Indirectly they are affected by increasing storage of surplus RES-E. The **newly planned hydrogen plant auctions, however, will directly influence the competition in hours with low RES-E share** where thermal power plants, DSM, imports, pumped storages and batteries will compete for rents. Subsidies will give a group of backup plants (hydrogen combi or sprinters) a huge advantage.

The degree of interference will strongly depend on the exact design of the support schemes which are still unknown (i.e., capacity payments and fixed strike price vs. market premium to lower power price risk vs. strike prices indexed to hydrogen reference price, Contracts for Difference (CfD), etc).

In any case those new support schemes will make investments in unsupported capacities much more difficult. Even if the planned auction volumes are only 8.4 GW H_2-ready thermal capacities, which is only a fraction of the immense thermal capacities needed until 2030 and beyond, they bear risks: Investors that have not been successfully in the auctions may refrain from the realisation of their projects or wait for new auction volumes. This attentism may result in a slippery slope: Small supported capacities may lead to more and more needed subsidies to bring dispatchable capacities and storages into the market until all assets are subsidised. These new well-intentioned support schemes may result in an unintentional (not fully thought through) capacity market.

Decision makers can do a lot to foster investments if schemes are designed adequately and communicated effectively. In the case of the new schemes this means in particular bringing clarity on the details how plants are supposed to be supported and a clear vision on how unsupported plants can compete (i.e., which revenue streams they can rely on). If uncertainty remains, the needed investments in thermal plant capacities will not be made.

Three possible market designs to foster investments in backup capacity

We have shown that all three possible revenue streams for dispatchable power plants in Germany need to be improved to attract investments in urgently needed thermal backup capacities:

- The **Energy only market** has proven to work in signalling scarcity via prices, but has failed to attract investments in new backup capacity required for generation adequacy. However, the highly debated but not yet further clarified deep reform of the European power markets with a possible abolishment of the merit order principle has induced high uncertainty.

- Tools with **capacity remuneration mechanisms** within the strategic reserve have either not been designed for newly installed power plant or will not be continued. None of the tools provide sufficient incentives to invest in new thermal capacity.

- Payments for increasingly important **ancillary services** can be an important revenue stream if paid for fairly. This is not always the case.

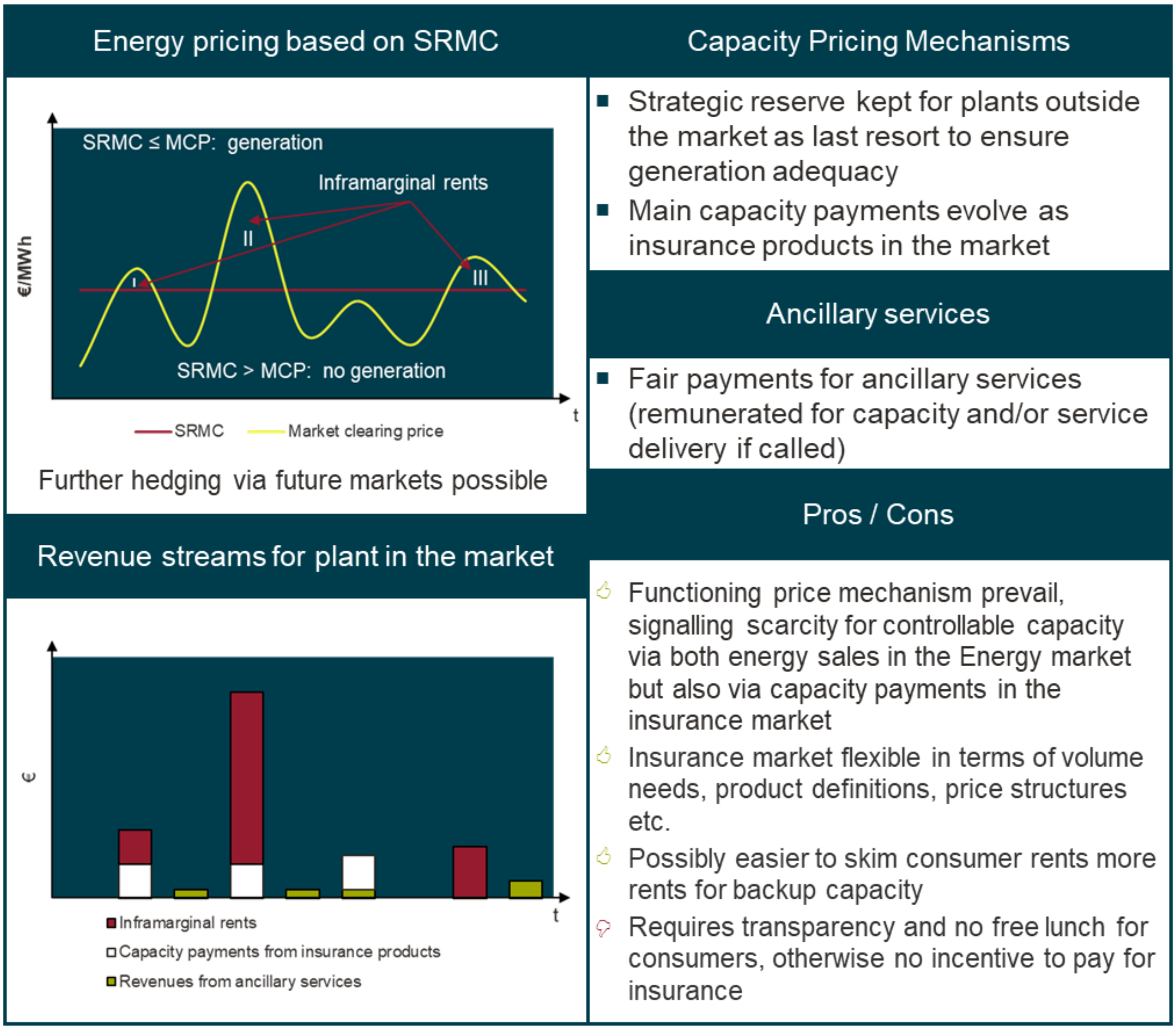
Based on these findings we design three different publicly organised set ups of revenue streams that could efficiently incentivise investments in thermal power plant capacities providing a stable and clear market environment. All three options entail the possibilities to generate revenues from energy sales, from capacity provisions and from ancillary services. In all three cases the merit order principle leading to inframarginal rents prevail in order to benefit from functioning pricing mechanisms, signalling scarcity. Hedging opportunities in forward markets or via PPAs are kept and fair remuneration for all ancillary services is ensured.

Energy only market with market-based insurance products

Within the first market design (**Figure 11**), the Energy only market with market-based insurance products, margins to cover CAPEX and fixed O&M in scarce hours are mainly generated via energy sales. Possibilities to hedge market risks via future/forward markets exist. A small strategic reserve is being kept for old thermal plants outside the market as last resort when the energy markets do not clear. Furthermore, controllable plants within the market offer (parts of their) capacity in form of insurances which evolve via market products driven by balancing responsible parties exposed to imbalance prices. All ancillary services are fairly paid either for the capacity and/or the service delivery if called. Scarcity is signalled via prices on both the energy and insurance market and ensures a sufficient provision of needed controllable capacity (i.e., thermal power plants). Flexibility on the insurance market possibly makes it easier to skim consumer rents, which results in more rents for controllable capacities. However, the system based on products developed on the market requires high transparency and no free lunch for consumers in order to incentive to pay for insurance.

The key issues associated with this market design are a free rider problem and a significant risk to system reliability. Without forward-looking price signals providing renumeration, generation adequacy could fall behind during periods of fast load growth driven by the electrification of transport and heating required for decarbonization.

Figure 11 Energy only market with market-based insurance products



Source: Frontier Economics

Case Study: California's Energy Crisis of 2000-2001

In the United States, California's Energy Crisis of 2000-2001 was the result of a too short-term focused and thus narrow market design, combined with a decade of insufficient investment in new generation to keep pace with load growth. In response to the reliability issues experienced during this period, the state implemented a mandate requiring utilities to demonstrate generation adequacy through procurement of dependable capacity. This approach has incentivized investment in new power plant capacity through a market-based mechanism guided by state reliability planning.

Energy market with scarcity pricing feature and market-based insurance products

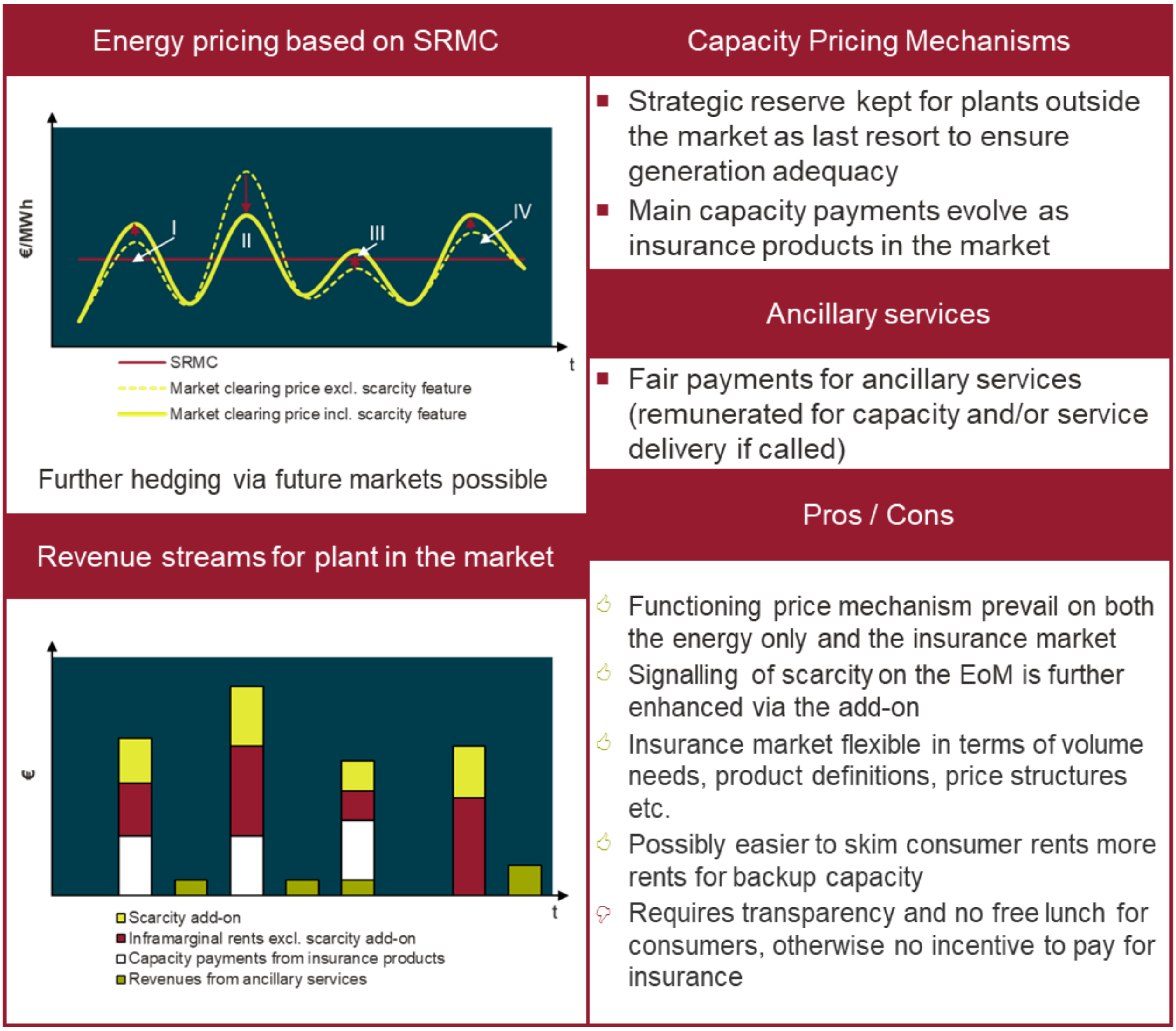
The second market design (**Figure 12**) the Energy market with scarcity pricing feature and market-based insurance products, differs only in the implementation of a further scarcity pricing feature which can help the energy only market to send the correct pricing signals to energy suppliers during periods of energy scarcity. Wholesale prices in the real-time energy market increase automatically as available operating capacities decrease, beginning at small amounts added to the system-wide wholesale price up to the price cap as available operating capacities get closer to a predefined level. A regulated somewhat "artificial" scarcity add-on is introduced as a "pre-warning" The scarcity add-on will result in a spreading of margins across more hours for controllable plants, but will flatten the price peaks even with the add-on. This is because the overall rents need to stay below costs of market entry. If bids are not adapted and rents are very attractive market incumbents provoke new market entries (as long as this is technically possible and not limited by site or network access restrictions or complex approval procedures). The scarcity add-on helps to further signal scarcity. However, adding a further price component that is higher in times of already high prices may be politically not feasible and the application rule to be developed might require complex analysis on (available) capacity situations etc. It might also cause adhere incentives for suppliers to artificially reduce the perceived capacity supply depending on the details on how the add-on is calculated and applied.

Case Study: The risk of missing long-term price signals – the example of Texas

A market design based on an EoM including insurance capacity products was implemented in the United States by the Electric Reliability Council of Texas (ERCOT) in 2014. For several years it did not produce significant long-term price signals, which contributed to large retirements of existing dependable generation and insufficient investment in capacity to replace it. In the summer of 2019, the price signal produced meaningful revenue for generators, indicating scarcity through high wholesale prices. Then, in the winter of 2021, Texas experienced an electric reliability crisis driven by cold weather in which about 40% of the generation fleet experienced outages and the TSO (ERCOT) was forced to leave millions of customers without power for multiple days. While weather was the catalyst for this event, it also indicated a failure in the energy only market design without functioning long-term price signals i.e., via liquid forward and future markets. A similar storm in the winter of 2011 had already raised concerns about the resiliency of the power system and recommendations for taking preventative measures to ensure reliability were mostly ignored by power plant operators, because making these investments (i.e., weatherisation) could have put them at a competitive disadvantage in the energy only market.

During this event, wholesale power prices in Texas surged to unprecedented levels. However, this price signal did not prevent the crisis because it was received too late. Also, there were significant political consequences due to the impacts of these extremely high prices on consumers. Multiple high-ranking officials with the Public Utilities Commission of Texas and ERCOT were forced to resign in the aftermath. To prevent a similar situation from occurring in the future, there is a proposal being discussed for implementing a mandate requiring utilities to demonstrate generation adequacy, similar to the market design California created after its 2000-2001 Energy Crisis.

Figure 12 Energy market with scarcity pricing feature and market-based insurance products

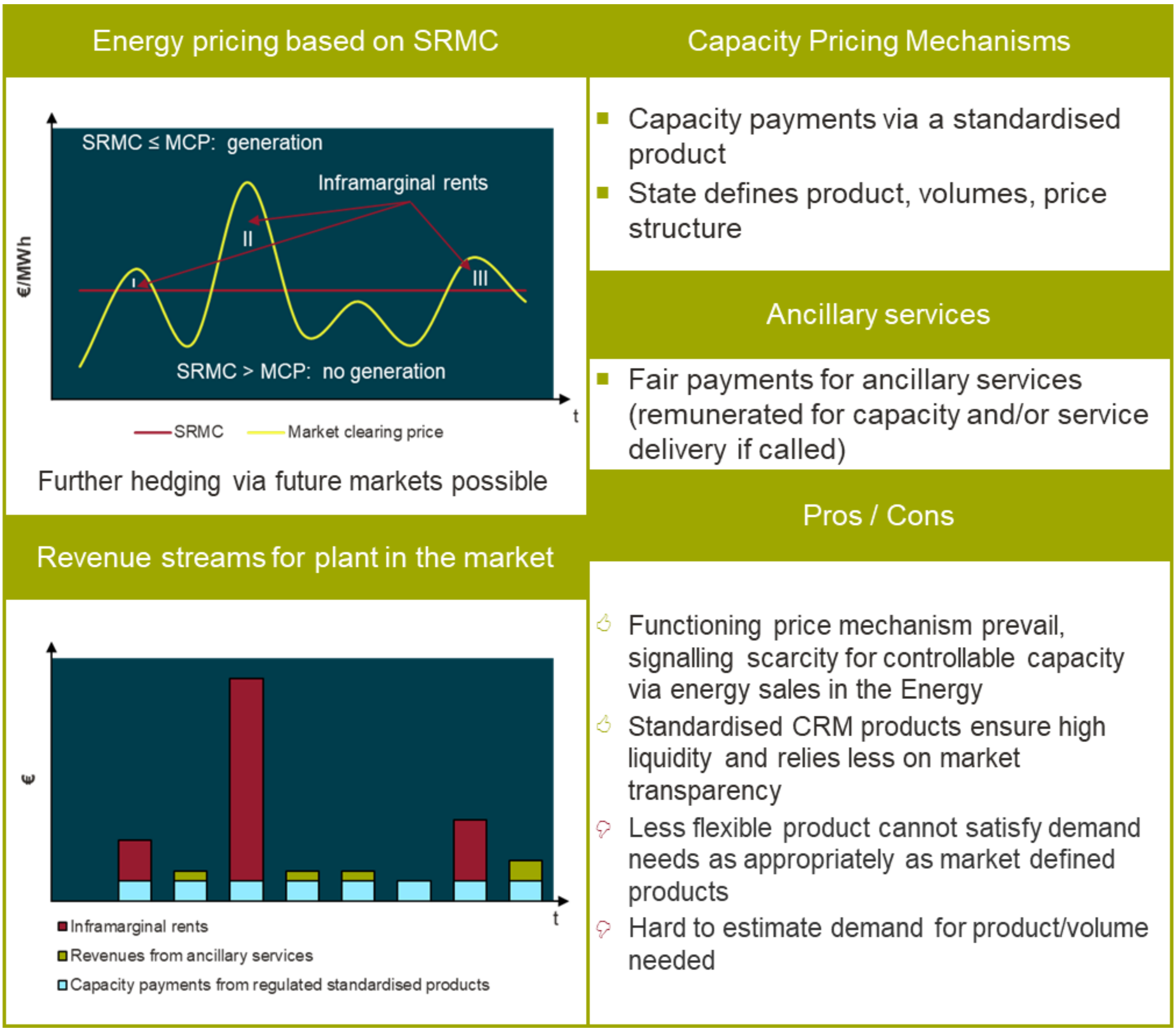


Source: Frontier Economics

Energy market with regulated capacity product

Within the third proposed market design (**Figure 13**), the energy market with regulated capacity products, the "insurance" products are not freely defined on the market, but are regulated standardised capacity products, defined by the state who also estimates needed volumes. Controllable power plants are allowed to bid for both energy sales but also the standardised capacity market. The standardised capacity products result in a liquid market which does not rely on a high degree of transparency in the market. However, the missing flexibility in the product definition and volume estimation may most likely result a lower satisfaction of demand needs. Furthermore, the regulated products require additional administrative efforts.

Figure 13 Energy market with regulated capacity product



Source: Frontier Economics

Case Study: Capacity auctions and Capacity Markets – the examples of US and UK

In US markets, there has been significant administrative effort and public controversy around the interaction between centralized capacity markets operated by TSOs and state policies promoting carbon-free energy. For example, the nation's largest TSO, PJM Interconnection LLC (PJM) had to delay its capacity auction for two years because of a proceeding with the Federal Energy Regulatory Commission. At the core of this was a concern that state-subsidized clean energy resources were putting downward pressure on auction clearing prices, making it more difficult for resources in other states without that advantage (PJM includes 13 states and the District of Columbia, all with different energy policies) to clear the auction. Currently, the most forward-looking capacity auction that PJM conducts is only one year ahead of the period it is supposed to ensure reliability for. Historically, that auction was conducted three years ahead, to ensure sufficient time for new power plant capacity construction.

In the UK, capacity auctions take place at both one-year and four-year ahead of time providing reasonable signals for capacity investments as well as resulting in diving down the capacity market clearing prices indicating a recovery in capacity shortfall.

Synthesis of potential market design options

The three presented potential market design options show the importance of diversified revenue streams, allowing for inframarginal rents from energy sales, capacity revenue and fair payments for ancillary services. Stacking revenue from these streams should be permitted, considering the multiple services thermal power plants can provide.

While the first market design option (i.e., the Energy only market with market-based insurance products) can be a good fit for Germany, it would need important improvements in terms of transparency, protection for investors from policy interventions in hours with high margins which are generated to cover fixed costs and decision makers need to mitigate the potential free rider problem.

In other world regions (e.g., in certain parts of the US) totally different approaches to power market design are applied – often systems with regional energy utilities, energy "pools" or "single buyers" and/or local system operators are used. In such a market design with an energy pool a single buyer/system operator collects all central generation and decentral auto-production from industry in one pool or via the "single buyer". A system operator is the coordinator of long-term system adequacy. All information being channelled, capacity or adequacy targets are easier to determine and to monitor. However, in Germany being a well-connected and central part of a European power system and also being part of a common European energy market that is not organised as a "pool" system, this design would require much wider and fundamental changes on a European level. Also, with millions of prosumers investing into decentral photovoltaic units, batteries, heat pumps and battery electric vehicles (BEV) that are coming up within the next decades, a centrally planned and efficient level of system adequacy is much more difficult to obtain and to monitor by the state or system operator.

Under the existing German EoM market design, price signals in liquid forward markets are expected to provide the longer term signal to investors expecting that individual investors will decide “what to make out of this in terms of volumes of required capacity investments.” However, this has also failed in providing the necessary stimulus to invest enough in the backup capacity in order to ensure generation adequacy in the system.

Regardless of which approach is chosen, in order to avoid the risk of blackouts or brownouts it is extremely important for investments in new generation capacity or to maintain existing capacity that investors:

- receive sufficient and timely (i.e., years in advance) price signals through liquid and transparent forward markets; and
- future projections of capacity adequacy (e.g., three years ahead) – that are co-ordinately produced by the Ministry of Energy, System Operators as well as the Regulator – and backed up by sufficient remuneration incentives to stimulate investments.

Recommendations to foster investments in backup capacities

Achieving the goal of climate neutrality by 2045 in Germany places high demands on our energy system. One crucial element of our decarbonised electricity system will be the sufficient availability of backup capacity which will mainly consist of thermal power plants. If we do not manage to maintain and grow the required market capacities in a timely manner, the generation adequacy of the German electricity system (in particular in the south of Germany) will be at risk with unforeseeable costs for consumers (households and industries) and the economy in Germany.

A lot can be done to facilitate the needed investments. In particular, **regulators need to provide clarity** on the following three aspects:

1. The participation **rules** in the future European and German power market.
2. The **remuneration** mechanism for flexible generation technologies.
3. The availability of **infrastructure** and **fuels.**

Clear rules for participation in the power market

The current energy crisis has induced a number of debates regarding the future power market design in Europe and Germany. In particular, the questioning of the merit order principle and related fundamental reform of the European power market announced by the European Commission in September 2022 has created a high uncertainty around the rules participants in the future German power market will have to follow. This makes well-informed investment decisions currently almost impossible. There must be clarity as quickly as possible on how the future power market design should look like. In any case, the following should be ensured:

- **A market mechanism with a functioning price signal needs to prevail**. The required volumes of backup capacities cannot be easily derived but depend on numerous developments in our energy system and beyond. State-based rigid volume planning may not always be able to provide an efficient amount of capacities. Examples in Germany like delayed wind offshore auctions which ended with “0” prices and needed a lottery to determine the auction winners as well as the volumes in the national hydrogen strategy which have been corrected upwards show that it is incredibly difficult for the state to plan volumes. Theoretically, it is preferable to **allow market mechanisms to determine the needed volumes.** However, this requires a high degree of transparency in the market, acceptance of price peaks as well as clear responsibilities (there can’t be free lunches i.e., for balancing responsible parties). Also, lead time of capacity build out may put the effectiveness of an energy only price signal in question. Therefore, transparent and liquid forward markets will be required to ensure a timely price signal. Sending price signals years in advance could also be achieved, for example, through state-mandated generation adequacy requirements for electric utilities like in some states in the US or for other balancing responsible parties.[33]

- **Technology agnosticism** is critical to allow technological innovations for development of most efficient future solutions. We will need a variety of technologies to ensure both security of supply and timely decarbonisation (i.e., SNG fuelled gas plants or natural gas with CCU/CCS).

- The **new support schemes for hydrogen power plants** (sprinter plants and combi plants) envisaged in the EEG 2023 are first steps to incentivise investments in dispatchable capacities that run on hydrogen. But many questions regarding hydrogen supply and cost as well as flexibility during the fuel-switch from natural gas to hydrogen remain open and pose a risk to investors. Clear and transparent participation rules for the support schemes will allow for efficient market outcomes based on clear goals (climate, security of supply) and an adequate carbon price. In any case they need to be designed carefully but quickly. They will need to be different from existing support schemes and reserve products for two particular reasons: First, different to existing reserve products (i.e., network reserve, capacity reserve), the hydrogen plants within the new support schemes will most likely not be kept outside the energy market but will be allowed to sell electricity and, thus, interfere with price formation. Second, different to existing support schemes for renewables, the new subsidies aim at dispatchable plants. As backup capacities on the energy market, they will aim at hours with low RES-E infeed - which are the hours where (unsupported) generation/flexibility sources like hydrogen plants, DSM, imports, pumped storages and batteries need to cover their costs. Thus, the new schemes will interfere with competition in the energy market and advantage subsidised capacity significantly. Furthermore, it needs to be clear that any proposal should address the risk from volatile fuel prices (i.e., for green hydrogen), a risk that Wind on/offshore and PV plants do not face.

- **Locational scarcity needs to be visible**. Locational signals are important to reveal scarcity of local generation or transmission capacity in certain regions (i.e., in the South of Germany). Alternative bidding zone configurations, as currently discussed and analysed in ACER's bidding zone review, should be taken into consideration as well as other options like locational network tariffs or locational signals as part of auction design.

- At the same time, it needs to be ensured **that bidding zones stay large enough to provide liquid markets** that enable hedging strategies. Furthermore, investment decisions won't be made under constant uncertainty about bidding zone reconfigurations. Once decided upon, the new bidding zones should be kept stable to allow investors to plan.

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33 However, lessons learnt from other electricity markets cannot be simply transferred to the German case, but should be rather seen as case studies for further evaluation. Changes in the functioning of a market need to fit within the overall market design which can differ quite significantly between electricity markets.

Clear remuneration mechanism

Decision makers need to provide clarity on **the envisaged remuneration mechanism for backup capacity** quickly. One guiding principle should be that **all services** provided by backup capacity are paid for which means fair remuneration for (a) power generation, (b) capacity availability and (c) ancillary services.

- Backup capacity will generate electricity only during a limited amount of hours. Prices must not be distorted (i.e., via highly debated price caps) but need to **allow for sufficient rents**. This means that price peaks need to be accepted. Furthermore, there must be clarity as quickly as possible on how the deep reforms of the electricity system targeting the merit order principle announced by the European Commission should look like. The so far rather broad concepts described in the European Commission's Non-Paper from end of October 2022 including CfDs for inframarginal technologies or the subsidy scheme mechanism at EU level inspired by the Iberian model do not allow for any planning.

- The availability of secure and flexible capacity is important to compensate for the variable RES generation and should be remunerated. The **design and formation of capacity remuneration elements must be clear**. They can either be organised by the state/regulator in form of highly standardised capacity products or be built up via the market in form of "insurance" products. Ex-ante none of the approaches is systematically preferable – market-based insurance products are more flexible in terms of volume, product definition and pricing structure whereas standardised products are much more transparent. For insurance products to play a role, there must be a credible consequence (penalty) for balancing responsible parties if generation and load are not balanced. There can't be a free lunch (i.e., in form of state-based rescue schemes). Otherwise, no one would invest in such insurance Regardless of which approach is chosen, it is extremely important to send price signals years in advance to sufficiently support investment in new generation capacity, through liquid and transparent forward prices. A middle ground between relying on insurance products without government oversight and a centralized capacity market could be establishing state-mandated generation adequacy requirements for electric utilities or balancing responsible parties ("BRP") that create multi-year capacity procurement obligations. This would incentivise bilateral contracts for generation that provide renumeration for backup capacity, which could be uneconomic to build based on energy market revenue alone. While in an energy only market the idea is to incentivise BRPs to invest into capacity via the (credible) "threat" of the high energy price in scarce situations (and each BRP then "translates" the threat/risk into an individual back-up capacity procurement strategy[34]) the state-mandated procurement obligations already determine the amount of capacity an individual BRP has to procure. The benefit of the state-mandated procurement is that it is more transparent and the targeted capacity level is likely to be reached, the drawback is a much more complex system to

34 The BRP or utility can decide how to procure the required back up capacity: it can invest into generation itself, procure options with a fixed option price (EUR/MW) and an ex ante fixed strike price (EUR/MWh) from other back-up capacity holders or can buy PPAs with a guaranteed profile (in that case the PPA seller has to back up the profile with his own assets and "smears" the capacity costs as part of the PPA price in EUR/MWh).

be established and monitored[35]. Both options allow the market to decide which backup resources are most economically efficient to be procured. However, the state-mandated obligation route would require a fundamental different market design setup in Germany and Europe (i.e., regional utilities pool or single buyer model) and/or complex rules to determine the efficient level of obligation for BRPs.[36]

- **Ancillary services are key to secure the grid stability and need to be fairly remunerated**. Foreseeable and fair payments in form of market-based payments (i.e., for frequency control) or regulated prices (i.e., reactive power for voltage control) can make a difference when making investment decisions. If new investments into instantaneous reserve products ("rotating masses") are required from a system perspective this "service" should be compensated.[37]

Secured availability of infrastructure and fuels

Lean and streamlined regulation must ensure **that the availability of all needed infrastructures in electricity and hydrogen generation and transmission** are synchronised. Approval and permitting procedures must be clear and fast. The time span between planning and commissioning of generation capacity or grids is usually several years and hinders the quick availability of urgently needed capacities. The unprecedented fast-track procedure for the construction and operation of a connecting pipeline for the planned LNG terminal in Wilhelmshaven has shown how quickly procedures can be and should serve as a blueprint for any future approval and permitting procedure. Furthermore, the sufficient provision of fuels needs a clear and reliable certification system of climate-neutral fuels and the possibility to enter long-term commitments. Dedicated single buyer models like the German Hint.Co as intermediary absorbing parts of the volume risks are promising and could also decrease the certification risk significantly. Hint.Co should be executed quickly, clarifying missing details around the scheme as quickly as possible. Furthermore, it should be established as a long-term measure to ensure investment planning. Also, the access to capital markets needs to be clear for all market participants. Uncertainties around EU Taxonomy need to be clarified quickly and should be aligned to fuel availability.

If investors have clarity on the market rules, revenue streams and certainty on the availability of infrastructure and fuels the needed projects in backup capacities to ensure the German generation adequacy will be realised. But we need to move fast and reduce political and regulatory risks where feasible as quickly as possible. Otherwise, the German generation adequacy will stay at risk.

35 The level of obligation has to be set for each BRP, rules for forecasting, rules for changing of customers to other BRPs and also "capacity credits" have to be defined to certain capacity types that qualify to fulfill the obligations.

36 In theory, the optimal level of obligation results in an efficient balance of "generation adequacy" and "cost efficiency" for the whole system taking into account uncertainty of future developments.

37 It can be argued that "rotating masses" come automatically with any turbine (and cannot be separated from the generation investment). While this is true once a turbine plant has been built, it can make a difference during the investment decision, i.e., when there are options with rotating masses (i.e., involving a turbine) and without rotating masses (i.e., PV, battery).