

Assessing the flexibility of coal-fired power plants for the integration of renewable energy in Germany

October 2019

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Executive summary

A key characteristic of power systems is that the demand and the supply of electricity need to be continuously balanced. Any deviation between demand and supply could lead to disruptions of the electric frequency and trigger reliability issues such as failure of components, or in the worst case an entire blackout. Frequency deviations should thus be kept within a narrow band of tolerance.

Wind and solar power are weather-dependent sources that introduce variability and uncertainty to the system, thus, challenging the balance of the demand and supply. The capability of following and balancing the aggregated swings of demand with variable renewable energy infeed is referred to as power system flexibility. Therefore, the integration of high shares of renewable energy is often considered a flexibility challenge.

More than 80% of a total of nearly 24.2 GW of installed coal-fired¹ power plant in Germany (end-2018) were built before wind and solar power made any meaningful inroads to the Germany power market. Their initial design was thus optimized for baseload and mid-load provision rather than cycling operations, now generally raising questions about the ability of coal-fired power plants to provide the necessary flexibility. **The shares of wind and solar power can be expected to continue growing.** Not only are the decreasing costs for these technologies gradually tilting the economic calculation in their favour, but the German government (alongside other European nations) has also set itself ambitious targets to further expand deployment of renewable energies.

This study has two primary objectives: first, **assess how the need for power system flexibility grows in Germany as wind and solar power are further expanded.** Second, **assess whether and how the existing coal-fired power plant fleet in Germany can accommodate and integrate growing shares of variable renewable energies, without jeopardizing reliability of electricity supply.** Specifically, we are studying **whether renewable energy shares of 50%, 60% or 70%** (as compared to the 38% reached in 2018) **would alter the way coal plants in Germany are operated and whether their technical characteristics are compatible with a further increase in wind and solar power.**

The main technical characteristics that determine the flexibility of a thermal power plant are start-up duration and cost, minimum load level, ramping speed, minimum operation time and minimum down time. We collect data on all of these parameters through literature review and expert consultations, discuss and feed those into our in-house power system model DEEM. DEEM is a mixed-integer, linear optimization model of the European power system that dispatches power plants on an hourly basis, explicitly taking into account the above-mentioned operational constraints.

Taking stock: model runs, carried out for the years 2015 and 2018 demonstrate that in these two years coal-fired power plants have been instrumental for integrating fluctuating output from variable sources into the grid. The years were chosen to obtain a maximum difference in renewable energy share (32% in 2015 vs. 38% in 2018) while still having a complete set of power market data available for model validation (data prior to 2015 is incomplete, notably regarding hourly infeed of wind and solar power).

¹ Throughout this report the term coal refers to hard coal only. Sub-bituminous coal types, such as brown coal, are referred to as lignite.

Looking ahead: model runs, carried out for **renewable energy shares of 50%, 60% and 70%** suggest that the existing dispatchable fleet in Germany, including the installed coal plants, pose, from the point of view of flexibility, no barrier to further expansion of variable renewables. The flexibility metrics developed in this study indicate that **coal plants ramp more often and cycle more intensely as the share of renewables increases**. (Technically speaking, the plants change their operational status – offline, online, minimum load, full load etc. – more often). Hence, we find that **coal-fired plants contribute to the provision of “short-term” flexibility by adjusting their energy contribution and by being dispatched more flexibly and at moments when they are most valuable for the system**.

Moreover, by analyzing the contribution of coal plants during “dark cold doldrums”, (i.e. cold spells coinciding with meteorological conditions that result in limited output from wind and solar plants) we find that their role for providing “mid-term” flexibility, becomes more important with increasing shares of renewables. **By analyzing such periods of tightness with durations of one to three days, we find that during such events, coal-fired power plants generate twice as much power than on an average day if the renewable energy share is 50%, and three-and-a-half times more power if the renewable energy share is 70%**. Another finding is that the weather conditions leading to “dark cold doldrums” also affect Germany’s neighbouring countries to a degree: although Germany becomes a net-importer during such events, **the scope for balancing via higher imports is constrained by the availability of dispatchable plants in other countries and congestion of interconnectors**.

Coal-fired power plants contribute, as other dispatchable plants, to system security via flexible adjustments of their output and through the provision of firm capacity. **Nevertheless, output from coal-fired power plant drops as the share of renewables increases** but remains, with 45 TWh in a 70%-renewables scenario (compared to 72 TWh today), significant. **The average load factor of the fleet drops to just over 30% in the 50% renewables scenario** (in comparison, the average load factor stood at 35% in 2018) **and further to around 20% and 15% in the 60% and 70% renewables scenarios respectively**.

However, the coal fleet is not homogenous; neither in its age structure nor in its technical characteristics. The various plant types thus react differently to increasing shares of renewables. Unsurprisingly, modern and thus more flexible plants, adapt more easily to the changing market conditions. **The latest designs achieve load factors far above the fleet average. In contrast, some of the oldest plants hardly run at all, being dispatched only in the tightest hours of the year**. In our modelling framework such plants contribute to the system stability and adequacy but whether they could be profitably operated based on energy-only market revenues is questionable. This problem is not unique to old coal plants but also affects gas-fired power plants. It forms the heart of a debate around what market designs can safeguard the integration of variable renewables without jeopardizing the economic viability of the dispatchable fleet.

Nearly three quarters of the installed coal fleet in Germany produce heat and electricity at the same time, which is both a challenge and an opportunity for flexibility provision. Most of the Combined Heat and Power plants are so-called extraction turbines which can switch between heat and electricity flexibly and seamlessly (i.e. minimizing losses during times of high renewables infeed) as long as electricity output is not constrained by heat demand during cold weather periods. In either case, **thermal storage retrofits can improve the operational flexibility of coal plants**.

The results of this model-based analysis demonstrate that a significant part of the existing coal fleet is technically capable of providing flexibility for the integration of renewables. Whether, in the future, the necessary flexibility will actually be provided by these coal plants primarily depends on **two other factors** that were not assessed in this study:

- First, the relative fuel costs between coal and natural gas, including CO₂ prices. **The relative fuel and CO₂ prices chosen in the prospective part of the study reflect the economics between coal and gas plants broadly observed over the years 2015 to 2018** (despite the assumed increase in CO₂ prices), i.e. a price constellation that places the bulk of the coal-fired fleet before gas-fired plants in the merit-order. Coal-fired plants are thus – as long as their technical characteristics permit – dispatched before gas-fired plants, if the system needs additional generation to meet demand. **A higher CO₂ price trajectory** than the one assumed here (which is based on the estimations of the World Energy Outlook 2018 of the IEA for the New Policies scenario) **or a lower natural gas price trajectory, could thus lead to a ‘fuel switch’** and place gas before coal in the merit order and higher flexibility would be provided by the gas-fired fleet.
- Second, the actual power mix that is in place when renewables reach shares of 50%, 60% and 70%. **The future power mix is, not only in Germany, increasingly determined by policy decisions** (nuclear phase-outs, coal phase-outs, renewable capacity targets etc.). **Moreover, there is considerable uncertainty around the future economics of innovative flexibility technologies, notably battery storage.** The model runs are thus not based on a least-cost expansion of the fleet or a ‘best guess’. Instead, we keep the installed coal and gas-fired capacity constant at today’s levels and combine this with the renewable energy deployment pathways as outlined in DENA (2019). Nuclear capacity is set to zero as, even under the most optimistic assumptions, a 50%-renewable energy share is unlikely to be reached before 2022. Policy guidelines or the uptake of new technologies could thus determine how much flexibility is provided by coal plants at what point in time.

1 The flexibility challenge

Key takeaways

1.1 Flexibility is not a new topic for power systems operation. System operators have a long-lasting experience in dealing with flexibility, ensuring the instantaneous balance of demand and supply. Nevertheless, the issue of flexibility has been exacerbated in recent years due to the fast uptake of weather-dependent energy sources such as wind and solar. The challenge of integrating high shares of renewable energy lies with their natural variability which can be interpreted as a flexibility challenge.

The first step for overcoming this challenge is the characterization of the type and extent of flexibility requirements. By analyzing the remaining load that needs to be fulfilled after accounting for the infeed of renewables it is possible to quantify the system effects of variable renewables. Flexibility requirements entail an energy, a capacity and a ramping dimension, which are system and time specific.

1.2 The options for providing flexibility comprise three interrelated layers: the technical layer is determined by the flexibility attributes of the available generation capacity, the electricity network and the storage and demand-response capabilities of the system; the “administrative” layer providing the coordination among the different assets and stakeholders (i.e. the market and regulation design), and the “institutional” framework composed by the energy policies in place that could foster or hinder the provision of flexibility to the system.

The expansion of renewable energy creates new challenges for the operation of power systems. Wind turbines and solar PV panels are well-established technologies today and government targets put them at the heart of electricity supply in coming decades. However, as they are weather-dependent, their availability varies from time to time and it does not necessarily coincide with periods of high electricity demand. Power systems need to tackle this challenge and remain flexible enough to cover electricity demand and to keep the system stable. Therefore, the issue of power system flexibility has been at the heart of the research on renewable energy integration during the last years², where it has been approached and defined from multiple perspectives depending on the topics investigated. Flexibility can be defined from a system perspective or from the point of view of a generation unit; it can be dependent on the type of service it is required for, thus starting at the scale of milliseconds in the case of the supply of fast reserves, to days, weeks or even seasons allowing for capacity and energy arbitrage. Also, it can be assessed from the perspective of flexibility adequacy, or from the supply side for analyzing the capabilities of power plants to follow the load and the impact on their performance.

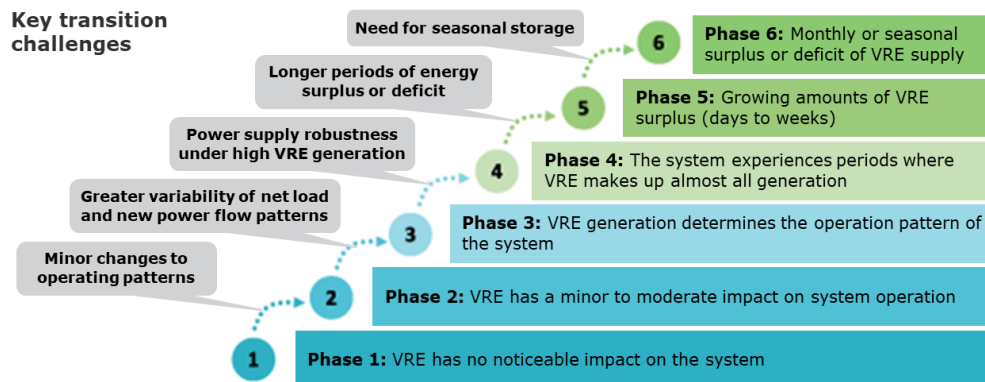
From the system perspective, the International Energy Agency (IEA) defines flexibility as “the ability of the power system to deal with a higher degree of uncertainty and variability in the supply-demand balance” (IEA, 2017, p. 14), and extends this notion by introducing the existence of “physical” and “administrative” flexibility. Physical flexibility is completely determined by the technical characteristics of the units composing the system (i.e. the modulation capability of generating units, the network infrastructure and the management potential on the demand-side) and forms an upper bound of the flexibility features of the system. Administrative flexibility deals with the existence of

² Comprehensive studies of wind and PV integration have been done under the initiative of the IEA under its Technology Collaboration Program (TCP). Those studies extensively cover multiple technical aspects of system integration of variable energy sources, including flexibility issues. Their findings can be consulted at: <https://community.ieawind.org/home>; and <http://www.iea-pvps.org/>

market incentives and duly defined and traded products (e.g. market clearing, lead time, time and spatial granularity, etc.) allowing the profitable modulation of power generation (IEA, 2018a, p. 2).

From the perspective of a power plant, Ulbig and Andersson (2015) define operational flexibility as “the technical ability of a power system unit to modulate electrical power feed-in to the grid and/or power out- feed from the grid over time”...“for achieving power balance, and within a grid topology, i.e. to control power flows via the modulation of power injections and outtakes at specific grid nodes.”

Figure 1. Phases of Variable Renewable Energy (VRE) integration



NOTE: Variable Renewable energies or VRE refers to weather dependent energy sources such as wind and solar.

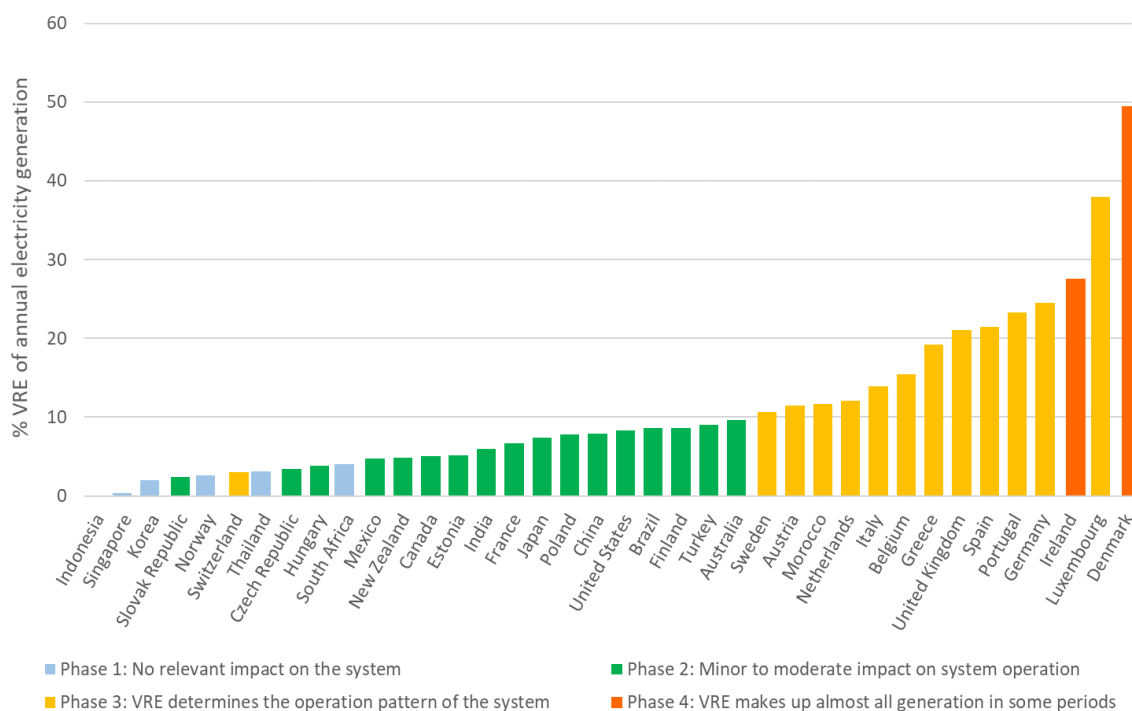
Source : (IEA, 2017)

Flexibility is not a new topic for power system operation. Load forecast errors and unit failures require monitoring and controlling procedures for balancing demand and supply deviations in real time; these are standard practices for system operators. Notwithstanding, the increasing shares of variable renewable energies (VRE) such as wind and solar have renewed the attention for flexibility issues during recent years. The rapid uptake of variable renewables in the context of the decarbonization goals is often considered a flexibility challenge, evolving through different phases and requiring different actions to be undertaken. The IEA describes six phases of renewable integration, defining different impacts on the system and determining specific flexibility requirements (figure 1). The actions required, and their associated costs become more prominent in every phase, and flexibility issues become noticeable and relevant at the transition between phases 2 and 3. Phase 5 and 6 are only roughly depicted by the IEA because, apart from small insular or isolated systems, there is still no real-life experience of such levels of renewable penetration in highly interconnected systems.

It is worth noting that the flexibility challenge and the resulting costs for integrating renewables into the electricity grid are system specific³ and should be carefully assessed. The IEA (2018b). recognizes this and classes different countries, depending on the share of variable renewables and their impact on the system, into the six phases of integration. The system specific character of the flexibility challenge is made explicit in figure 2 by the overlaps between phases 2 and 3 for Hungary and South Africa, and 3 and 4 for Ireland and Luxembourg.

³ Technical factors such as the geographical location and potential of solar irradiation and wind, the match between demand and infeed by variable renewables, the status of interconnections and cross-border capacity, the size of the balancing area as well as the technical characteristic of the power plants on the mix are key for accommodating increasing shares of variable renewables, but also administrative factors such as market design, network codes and operations protocols are relevant.

Figure 2. Phases of variable renewable integration by country



Source : (IEA 2019)⁴

Recent discussions on the topic highlight that even if power system flexibility is on top of the agenda for integrating high shares of variable renewables, a single definition for it has not yet emerged (IRENA, 2017, p. 37)(IEA, 2018b, p. 19). However, the following dimensions have reached consensus among experts:

- First, the notion of flexibility is related to that of energy balancing and capacity adequacy, but also the provision of network stability⁵. These services comprise a wide range of actions with different times for delivery and durations. While actions requested to provide network stability are deployed on a seconds to minutes scale, the balancing of energy is spread out from minutes to months, and 'capacity adequacy' ranges in the scale of years.
- Second, a difference between managing variability and dealing with uncertainty is often recognized. Variability refers to the fluctuation of demand that can be forecasted reliably⁶. Thus, the power system is required to be sufficiently flexible to deal with these swings and to follow fluctuating load. While variability can be scheduled (e.g. based on daily patterns), the uncertainty is related to deviations from expected values⁷ close to real time. The system should also be sufficiently flexible to adapt to unexpected changes of operational schedules and to balance such unexpected deviations.

⁴ Figure based on the post of the former head of the Gas, Coal and Electricity division of the IEA available at: https://www.iea.org/newsroom/news/2019/october/more-of-a-good-thing--is-surplus-renewable-electricity-an-opportunity-for-early-.html?utm_content=bufferefe04&utm_medium=social&utm_source=linkedin.com&utm_campaign=buffer

⁵ Network stability and frequency support are system services deployed by the system operator who is responsible for ensuring security, reliability and resiliency standards.

⁶ This is, for covering the contiguous variations of the load minus the infeed of weather dependent energy resources.

⁷ Due to forecast errors, load can be different than expected and further short notice deviations can appear coming from weather-dependent energy sources due to clouds, wind gusts, forecast errors, among others.

- Third, the nature of the flexibility requirements (e.g. the extent, the time for delivery, the duration) define the kind of services that need to be provided to operate the system in an adequate manner. Every kind of service has its own characteristics and can usually be supplied by various technologies.

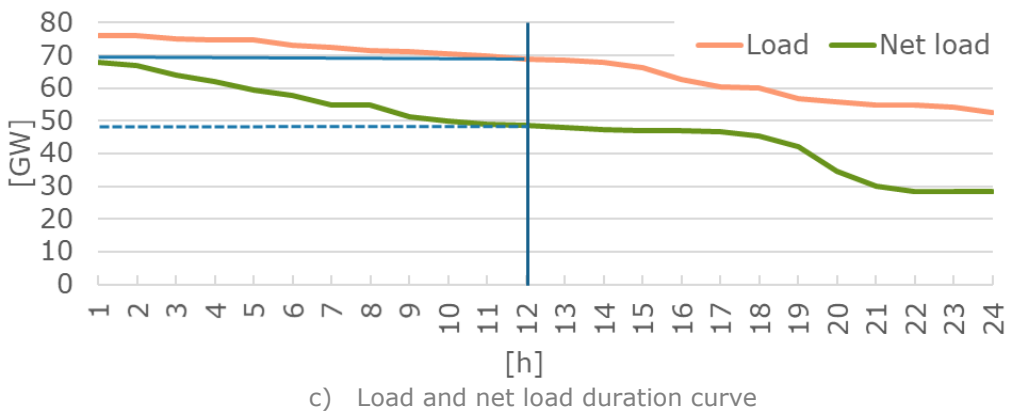
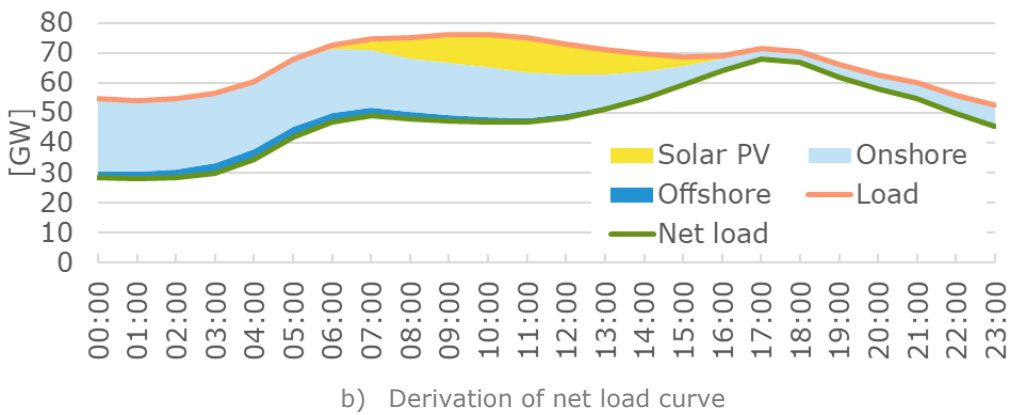
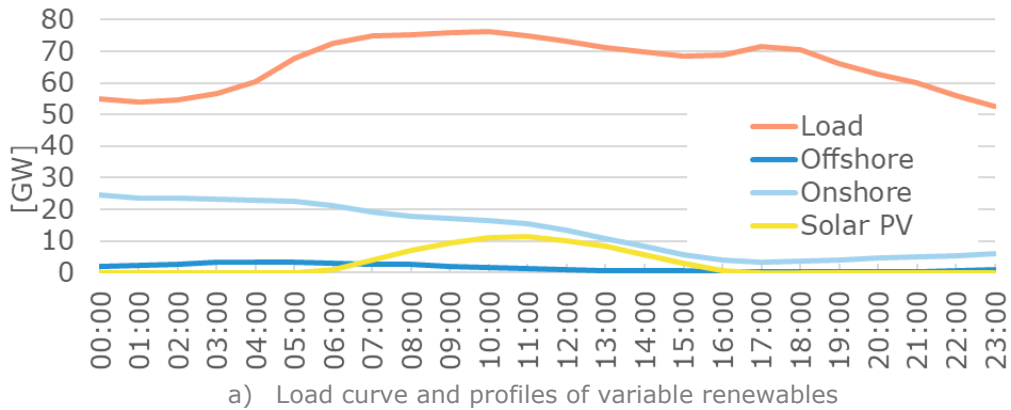
1.1 Flexibility requirements: The demand side

The need for flexibility in a power system arises from the fact that, to keep the lights on, the balance of supply and demand must be ensured at any point in time. In technical studies, the power demand at any given point in time is denoted as the load. More specifically, renewable integration studies typically focus on net load⁸ for assessing the impact of increasing share of variable renewable energies. Net load is calculated by subtracting the output of non-dispatchable capacities (such as wind and solar power) from load. Figure 3.a and figure 3.b illustrate graphically, for typical day, how the net-load curve is derived. While figure 3.a shows both, the load curve and the curves of variable renewable energies in absolute numbers, figure 3.b displays how the net-load curve is derived from the load curve by deducting the generation of variable renewables. For half of the hours of that day load is above 68 GW, while net load exceeds 48 GW for half of the time (Figure 3.c). Furthermore, to assess changes in ramping needs, so-called ramp duration curves have proven useful. Ramp duration curves sort the hourly difference of the load (or net load) in a descending order.

During periods of high demand and low renewable energy infeed, the system might experience a capacity scarcity episode, translating into high electricity prices. On the contrary and depending on the shares of variable renewable energies in the mix, low demand and high renewable energy infeed can lead to energy surplus. During such periods of excess supply, electricity should be exported to neighboring countries, stored and/or curtailed. Low or negative electricity prices occur at those times. Thus, the shares of wind and solar and their variability constitute a new market determinant on electricity markets.

⁸ The net load is also referred as residual load. Both terms are used interchangeably in the literature.

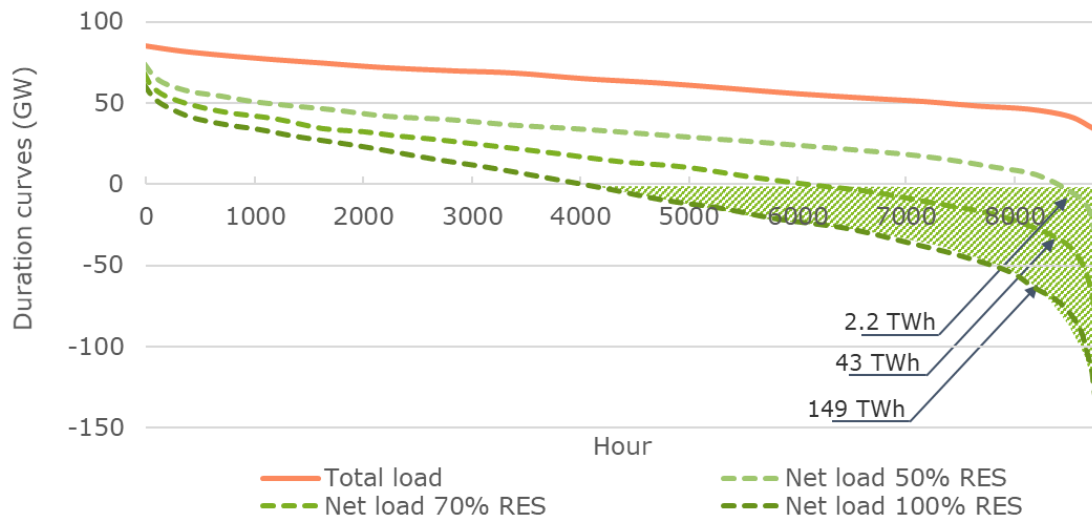
Figure 3. Derivation of net-load and load duration curves



Source : Own elaboration based on ENTSOE data

The load duration curve sorts the hourly (or other time steps) load levels of an entire year (or other time horizon, e.g. a day) in a descending order, starting with the hour of the highest load and decreasing until the hour of the lowest load. An example of load duration curve is shown in figure 3.c. It allows inspecting the amount of time (i.e. hours) the level of load and/or net load is within a window of magnitude. For instance, in the example of figure 3.c, the load is between 70 GW and 76 GW (i.e. its maximum) for during 12 hours while the net load is between 49 GW and 70 GW (i.e. its maximum).

Figure 4. Indicative net load duration curve in Germany for different shares of renewable energies



Source : Based on (Steurer et al., 2017)

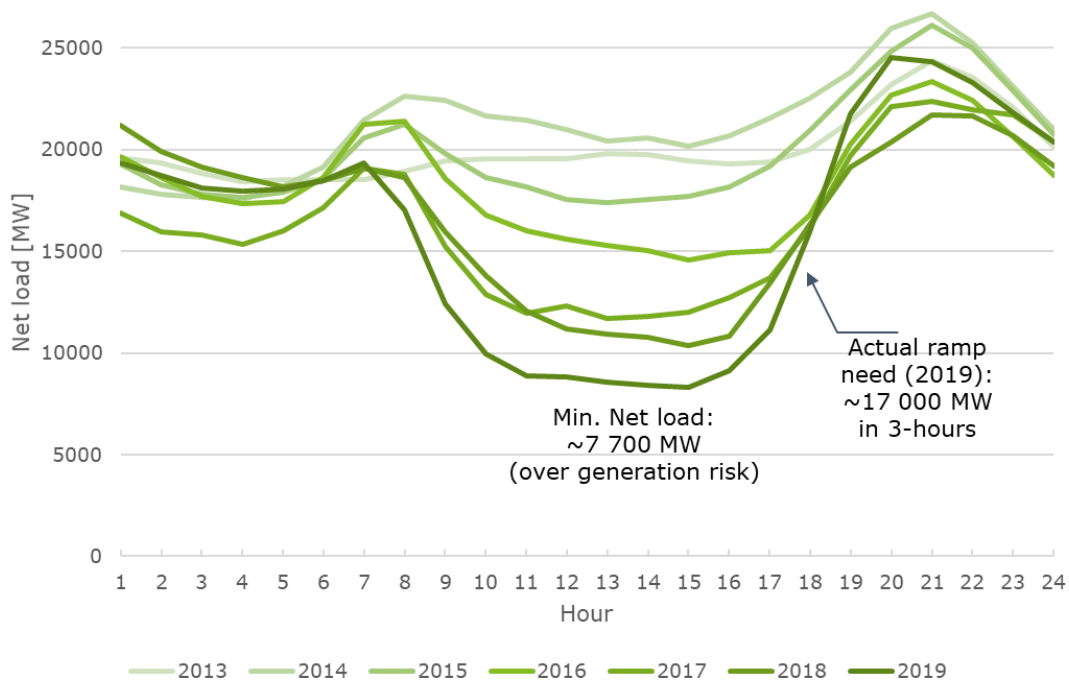
By analyzing the deviation of the net load (green dashed lines of figure 4) with respect to that of the load (salmon-colored line) for the entire year, we can assess the impact of increasing shares of variable renewables on the amount of capacity and energy required to balance the system. The way the tails and the areas behind the curve of the net load duration curve are transformed with respect to those of the original load gives interesting insights on the flexibility requirements (figure 4). The figure also shows both, the net load duration curves of Germany for scenarios of 50%, 80% and 100% shares of renewable as proposed by Steurer et al. (2017). The initial levels of the load duration curve (GW), the salmon-colored line, is inherently positive, indicating the total electricity demand of the system (GWh). But since the slopes of the net load duration curves become steeper with increasing shares of renewables, the net load duration curves cross the horizontal axis, becoming negative for a higher number of hours, so attaining a negative segment towards the middle of the curve. The positive area under the curves (i.e. to the left of the horizontal intersect) represents the amount of energy deficit that needs to be fulfilled by “flexible energy” alternatives, while the shaded area above the curves (i.e. to the right of the horizontal intersect) represents the energy in excess that needs to be managed by exporting, storing, or generation curtailing measures (with a share of 50% renewables, the number of hours with excess electricity is less than 500 h (hours on the horizontal axes from its intersection with the 50% load duration curve to the right end). The excess energy produced in these hours reaches 2.2 TWh. In the 80% renewable scenario there is already excess electricity in more than 2500 hours of the year summing up to 43 TWh in total. This amount increases further in the 100% renewable scenario to 149 TWh. In half of the of the year the generation of electricity by variable renewable energies is higher than the load.

Moreover, the right tail of the curves of figure 4 denotes the magnitude of the total capacity sinks that are required to handle the episodes of excess capacity, which occur only a few hours per year. Furthermore, capacity adequacy issues can be observed at the beginning of the curve (i.e. left tail) since the peak of net demand shifts downwards from low variable renewable shares until 50%, after which adding higher variable renewable energy capacity does not reduce the net peak demand any further. Even at a share of 100% renewable energies, still 70 GW, or around 75% of the peak load, need to be covered by available generation capacity other than variable renewable energies (whose contribution has already been accounted for in the net load). This is often pointed out by analysts as

the lower capacity value of weather-dependent energy sources when compared with dispatchable technologies.

Regarding power system operations, the challenges of managing increasing variability can be illustrated with the Californian “duck chart”⁹ (CAISO) (figure 5). The figure shows how the morning and evening ramps have been exacerbated, changing from around 3 GW in 2012 to around 11 GW in 2016 and they are expected to reach 13 GW by 2020. Such noticeable ramp episodes are due to the high solar PV infeed during daytime hours (between 7am and 6pm). In the morning, the uptake of generation from solar covers a significant share of demand causing a deep trough in net load at noon. During the afternoon, the generation from solar PV starts declining until it reaches zero by sunset (i.e. around 6pm). At the same time, the sunset coincides largely with the end of the working day, people go back home and the residential demand for electricity goes up. The fact that the infeed from solar PV goes to zero at the same time the demand reaches its daily peak during the evening hours exacerbates the daily ramping needs from around 5pm and 8pm on a spring day.

Figure 5. “The duck chart” for a typical spring day in California (31 March)



Source : (CAISO)

Electricity markets also point to flexibility requirements by pricing signals and market outcomes. Market data reveals increasing price spreads and market volatility during the last years. Furthermore, episodes of negative prices¹⁰ are becoming increasingly common in systems with high shares of

⁹ In a recent report, Scott Madden finds that “the “duck curve” is real and growing faster than expected”. Further information is available at: <https://www.scottmadden.com/news/scottmadden-finds-important-nuances-analysis-california-duck-curve/>

¹⁰ Negative market prices are rare market outcomes in the sense there are somehow counterintuitive and do not take place on the exchange of other commodities or stocks. They mean that a producer should pay a fee for generating electricity at this moment and that consumers are paid for using it. There are several reasons to explain such market outcomes, but the main factors are oversupply from renewables, demand inelasticity, and supply inflexibilities. In any case, the key for solving such situation is the enhancement of system flexibility. Further information can be retrieved at: https://www.epexspot.com/en/company-info/basics_of_the_power_market/negative_prices

renewables, and the curtailment of renewables is increasing too. Hence, the lack of flexibility in the system adds to the costs of integrating variable renewables, appraised by the market through negative prices and larger price spreads. This opens market opportunities for business models based on flexibility provision¹¹.

Therefore, the notion of system flexibility can be described by the three following dimensions:

- a. **The capacity dimension:** It is related to the available dispatchable capacity for managing the extreme load episodes during a few hours per year (i.e. the tails of the net load duration curve). The positive tail refers to generation capacity needed other than given by variable renewables, while the negative one denotes capacity sinks (negative capacity).
- b. **The ramping dimension:** Load following operations are required to counter the increasing volatility of the net load (i.e. the steepness of the net load duration curve). It comprises the system's capability of better following the net load, either by modulating the demand (e.g. by introducing demand-response programs) or by modulation of the generation (supply-side measures).
- c. **The energy dimension:** shifting energy between episodes of excess and scarcity. Thus, energy is buffered in a flexible manner. According to the frequency and extent of such episodes, energy can be shifted at different timescale going from day to night, weekday to weekend, or even between seasons.

In this study we aim at assessing all three dimensions of flexibility, ensuring the reliable operation of the power system in hourly timesteps (for entire years). Since these dimensions are closely interrelated, it is not possible to provide only one of them without requiring at least the provision of one of the others (i.e., it is possible to provide energy-neutral regulation/arbitrage by ramping up and down a unit in a way that the energy delivered sum up zero within a certain intervals, but every time a unit is ramped it unfolds its capacity dimension). For the sake of simplicity, we refer to short-term flexibility provision the association of the capacity and ramping dimensions, while we denote mid-term flexibility that of the ramping and energy dimensions within the year¹². Other aspects of flexibility related to contingency, transient analysis or requiring finer temporal granularity are beyond the scope of this report (e.g. frequency regulation, inertial response, black start capabilities, among others).

1.2 Flexibility options: The supply side

From a technical point of view, flexibility can be supplied by various technologies as long as they are capable of changing their output given a control signal. Flexibility suppliers are constrained by their installed capacity, energy and ramping characteristics. The ability of modulating the electricity output within the technical boundaries is referred as operational flexibility. Technologies that are highly reactive and can change their output rapidly are often considered as particularly flexible (e.g. hydro reservoirs and gas turbines).

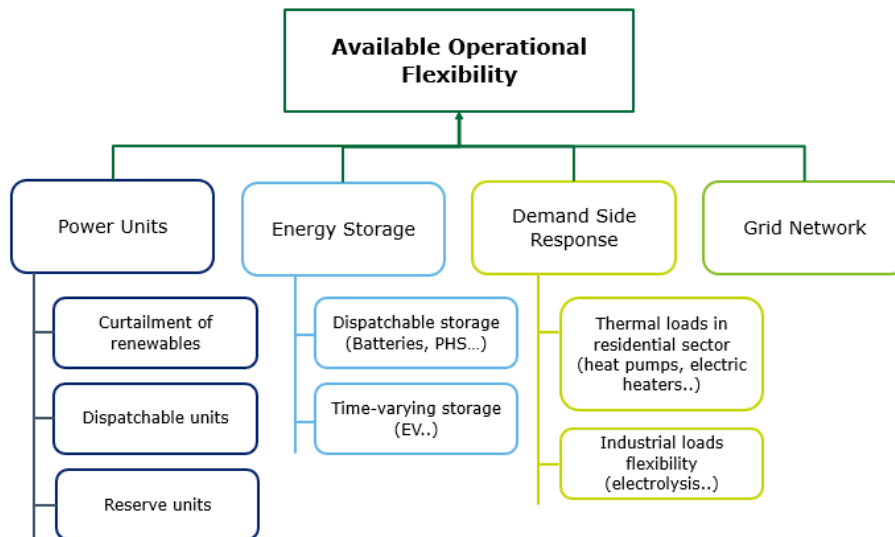
Nevertheless, any technology that can be scheduled, re-scheduled and dispatched according to a control strategy can offer flexibility to a certain extent, including modern wind farms, but also other thermal technologies. Another important source of operational flexibility is the electricity network, it allows smoothing net-load variability by improved matching of correlated demand and supply via enlarging the balancing area. Emerging flexibility technologies such as battery storage, demand

¹¹ Figure 40 of appendix A gives some insights on the increasing variability on the dispatch, price volatility and negative price episodes in Germany between 2012 and 2018.

¹² A more detailed discussion on this issue is presented in section 3.1.

response, electric vehicles, among others (i.e. belonging to what it is referred as “smart grid technologies”), allow smoothing out variability by giving the user (or operator) the possibility to benefit from changes in the electricity price.

Figure 6. Multiple sources of operational flexibility¹³



Source : Own elaboration based on (Ulbig and Andersson, 2015)

In the European electricity system, technologies compete on cost and their merits for the provision of various services on dedicated markets. Policies and regulation provide a framework for the coordination via market signals. Hence, in addition to the technical aspects determining the supply of flexibility (as introduced above), there are also important institutional aspects to take into account. For instance, a given technology could, from a technical and economic point of view, provide flexibility at a certain moment but the institutional framework could prevent it from doing so for several reasons related to policy goals, security and/or competition issues. Overcoming the flexibility challenge not only requires flexibility options to be available, but also encompasses a need for enhanced coordination of assets (i.e., through market products remunerating implicitly or explicitly the provision of flexibility¹⁴) and the design of supportive regulatory and policy schemes to ensure long-term signals for deploying them¹⁵.

Furthermore, depending on the integration phase of variable renewables a system is experiencing, different priorities related to flexibility requirements move into focus¹⁶. The potential of any technology to provide flexibility (determined by the technical aspects), the market design and the strategies to be followed (determined by the institutional aspects) are inherently system-dependent and evolve over time.

¹³ PHS (or PHES) stand for Pumped hydroelectric energy storage. EV stand for Electric vehicles.

¹⁴ Some examples include the implementation and reinforcement of intraday markets allowing trading at more granular timesteps and closer to real-time, and innovative products such as the RegD product of PJM and the flexible ramping products of CAISO.

¹⁵ The FERC’s order 841 is a remarkable example.

¹⁶ The idea that “...system integration challenges emerge gradually as VRE expand in a power system. Consequently, it is advisable to enhance the system’s ability to absorb variable renewables gradually, also.” is put forward by the IEA (2017, p. 47) in its policy recommendations during the first phase of variable renewable integration, but it can be generalized to any other integration phase.

Power systems are composed of different types of generating capacity that should progressively accommodate increasing shares of variable renewable energies. There is a broad portfolio of options and actions that should be assessed to succeed in integrating variable renewables. They include adapting plant operating guidelines for functioning closer to the design boundaries of components on existing units, improving market design, retrofitting thermal power plants for enhancing their flexible capabilities, investing in new flexibility technologies etc. During recent years, most systems with significant shares of variable renewables have implemented a combination of such options, starting by enhancing the flexibility provision of thermal power plants as a transitional mechanism¹⁷. The key factors to be considered are, for example, the technical capabilities of the existing technologies and their age, the renewable energy targets for the coming years/decades, as well as the current investment and operating costs of different technologies and their prospects.

¹⁷ For instance, by assessing the evolution of the dispatch of power units in Germany between 2012 and 2018 (see figure 40 in the appendix A), it is possible to see how not only the shares of conventional technologies have shirked during the last years but also their output have evolved with an important increase of ramping and cycling operations for complying with the increasing flexibility needs of the system.

2 Coal-fired power plants¹⁸ and their flexibility characteristics

Key takeaways

2.1 As any dispatchable power generation unit with, coal-fired power plants can be used flexibly to a certain extent, provided it is profitable to do so. The extent to which coal power plants can modulate their output is related to its operating principles defining the range of temperatures and pressure they can handle, and hence, the type of components and the control system in place. We can distinguish between sub-critical, supercritical and ultra-supercritical units regarding the steam temperatures attained in the boiler, and between pure electricity and combined heat and power units regarding their outputs.

2.2 The operational flexibility of thermal power plants, such as coal plants, is thus described by the parameters defining the range of set points they are capable to undergo by design. They are given by the minimum up/down times, minimum stable load, maximum power delivery, ramp rates, ramp and start-up costs. Regarding the combined heat and power units, the power-to-heat ratio and the power-to-heat loss coefficients also defines their utilization boundaries.

According to the last Status of Power System Transformation report of the IEA, in Germany, “flexibility is mainly provided by conventional generation. In particular, coal units are increasingly operated in a load-following mode. However, a significant amount of gas-fired capacity rests idle as it is largely unable to compete with coal. The potential of demand response has yet to be exploited.” (IEA, 2018b, p. 86). In 2019, with the drop in natural gas prices and the increase in CO₂ prices the situation has been somewhat reversed with previously idle gas-fired power plants coming back into merit, displacing coal plants.

This section aims to introduce the basic operating principles of coal-fired power plants¹⁹, with a focus on the flexibility capabilities of the German fleet in particular. The purpose is to provide the reader with insights on the main technical aspects that have made coal-fired power plants a key flexibility provider during the last few years in Germany. A detailed quantitative assessment of the current and prospective provision of flexibility from coal power plants is provided in section 3.

2.1 Basics of coal-fired power plants

The underlying thermodynamic process behind coal-fired power plants²⁰ is the Rankine cycle, where the thermal energy produced during the combustion of coal is used on a closed-loop water circuit to run a steam turbine. The simplest Rankine cycle comprises the following four phases: a phase of pressure increase through pumps, a temperature increase through the combustion of coal, an expansion phase in the turbine, and a condensation phase to bring back the fluid to the initial state.

¹⁸ In this report the term “coal” refers to the different types of hard coal, thus references to lignite are made explicitly in the text.

¹⁹ Further technical details and insights of coal power plants related to flexible capabilities can be retrieved on (Agora Energiewende, 2017; CEM, 2018; Garðarsdóttir et al., 2018).

²⁰ Most coal power plants are based on pulverized coal (PC), some others use a fluidized bed combustion variation. These are referred as conventional coal power plants. Only a few coal plants are based on Integrated Gasification Combined Cycle (IGCC), which are advanced plants combining a gasification stage before the combustion with a gas and a steam turbine to improve thermal efficiency.

The cycle runs continuously if the plant is operational. During the expansion phase, the high enthalpy²¹ steam is converted into mechanical energy in the turbine, coupled with an electrical generator, producing electric power.

Depending on the maximum temperature and pressure conditions the steam reaches during the cycle, the cycle might stay below the critical point of water²² or could exceed it. Typically, three categories of steam power plants can be distinguished: subcritical, supercritical and ultra-supercritical. Higher temperature and higher pressure of the steam yield better thermal efficiencies of the cycle but require more advanced materials and security considerations. Also, by adding further steam reheating and heat regeneration sub-stages to the cycle, it is possible to achieve better efficiencies. However, this implies a more complex process with increasing maintenance need, elevated outage risk and higher operating costs.

Even if coal and lignite-fired power plants follow the same thermodynamic cycle, the different characteristics of the fuel used, in terms of moisture (45-60% for lignite against 2-7% for coal) and energy density (8 MJ/Kg for lignite against 22-32 MJ/Kg for coal), lead to very different combustion and pre-combustion processes, as well as different types and sizes of fuel handling and burning components (e.g. beater-wheel and bowl mills). Due to simplified processes and smaller dimension of components, coal power plants usually display higher flexibility attributes than lignite-fired power plants (Agora Energiewende, 2017).

Combined Heat and Power (CHP), also referred to as co-generation, is common with coal-fired power plants in Germany. This technology allows for an improvement of the net efficiency of the process by using the partially expanded steam from the turbine (i.e. at medium temperature) to heat water through a heat exchanger. This intermediate heat is used to supply process heat for industry and/or serve heat demand in district heating networks. Co-generation minimizes the spillage of residual energy from low-temperature heat at the exhaust of the condensers. The two primary technologies for combined heat and power are back-pressure steam turbines, which produce electricity and heat at a fixed ratio, or direct steam extraction from the turbine which has the advantage of allowing for flexible ratios of heat and electricity production.

Due to the short-term inelasticity of heat demand, most CHP plants – independent of their fuel type – are operated in a heat-controlled mode. This means that they are considered as “must-run capacity” when they need to satisfy a given heat demand, which limits their flexibility of producing electricity. Alternatives, such as introducing thermal storage (e.g. water-based or solid medium), including auxiliary boilers (e.g. electrical boilers) or adding a turbine bypass, allow the decoupling of heat and power supply, which enhances the flexibility prospects of CHP plants.

2.2 Operational flexibility of thermal power plants

The operational flexibility of thermal power plants is determined by the range of feasible operating points supported by their technical design. This includes the speed at which they can adjust their output within this range, and the time they need to be ready from standstill to start feeding into the grid. Depending on the technology and design of each plant, each one of these features is related to a different process. Thus, different flexibility parameters can refer to multiple components, actions or procedures when operating the power plant. It also implies different costs depending on the

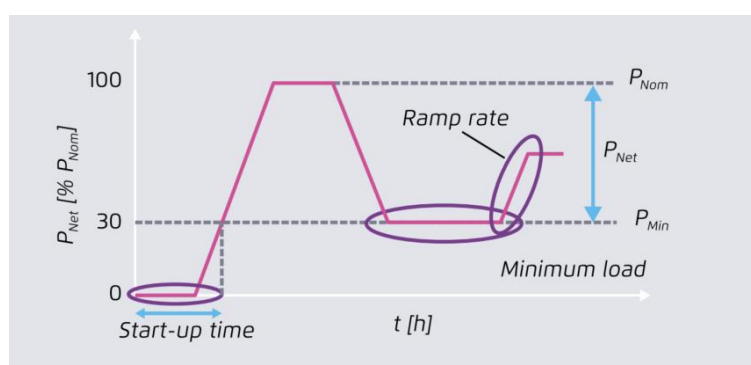
²¹ Enthalpy is a thermodynamic property quantifying the energy content of a substance comprising its internal energy, plus its temperature and pressure.

²² For water-steam the critical point is reached at 221.2 bar and 374.15 °C.

situation. Generally speaking, the technical constraints defining these features can be summarized by the following parameters:

- **Minimum up and down times:** It is the time to be considered to start-up from being idle²³ until grid synchronization status (i.e. for reaching the point of minimum load), and to shut-down from an operating point.
- **Cost of start-up and shut-down:** These costs are associated to additional fuel use and wear-and-tear costs due to mechanical and thermal stress.
- **Maximum load capacity (P_{nom}):** It is often referred to as the nominal capacity of the plant.
- **Minimum load capacity (P_{min}):** It is given as a percentage of nominal capacity.
- **Ramp-up and down rates and costs:** Rates refer to the steepness of an increment or decrease of output per unit of time. It is often given as a percentage of the nominal capacity per minute. Ramping costs refer mainly to wear-and-tear costs.

Figure 7. Indicative representation of key technical parameters of a thermal power plant.



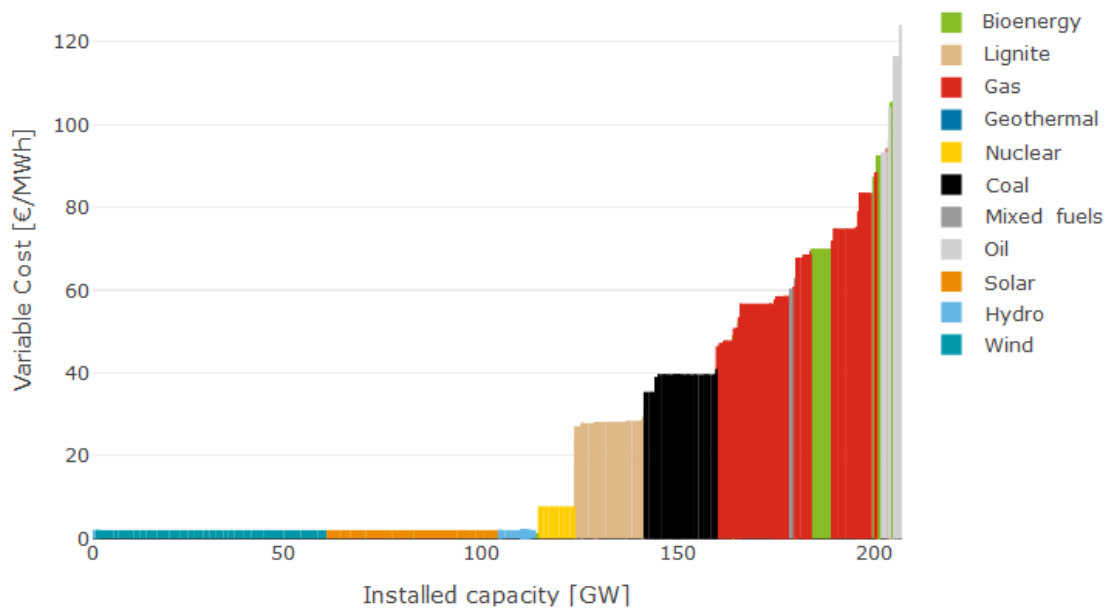
Source : (Agora Energiewende, 2017)

Thermal power plants are classed according to their place in the merit-order stack²⁴ which is mainly dependent on their variable cost, as illustrated in figure 8. Thus, generation technologies are considered as baseload, mid-merit, peak or extreme peak units²⁵. Lignite power plants are traditionally considered as baseload units, coal power plants as mid-load units, while certain gas and oil-fired units are usually considered peak and extreme peak due to their cost structure.

²³ Idle operations could imply a cold, warm or hot state of the plant. Cost and constraints of start-up use to be differentiated.

²⁴ In electricity markets, the merit order stack is obtained by ordering existing capacity by increasing marginal cost. The result is an approximated supply curve.

²⁵ A second factor defining the composition of today's electricity mix is the cost structure of different technologies (i.e. capital cost, OPEX, etc.). For a simplified explanation of generation capacity expansion models the authors refer to the methodology of "screening curves". With increasing shares of variability, capacity expansion methodologies are being evolved by introducing even higher detail of short-term operations on the capacity expansion calculations on loops or on an integrated way (e.g. economic dispatch and/or unit commitment).

Figure 8. Stylized merit order stack

Source : Own elaboration

Nevertheless, due to their low marginal cost renewable energy sources (RES) enter the merit-order at the very left side and, as such, shift the merit order stack to the right (i.e. this effect is called “the merit order effect”), pushing the units on the right side of the merit-order (i.e. peak and extreme peak ones) where they are dispatched less frequently. This implies that the power system runs with lower shares of gas and oil-fired units, requiring the flexible operation of baseload and mid-merit units. Thus, due to the evolving operating procedures and the technical modifications of thermal power plants²⁶, coal-fired power plants have been drastically changing the way they are dispatched²⁷ (Cochran, Jaquelin, Lew, Debra, and Kumar, 2013) to the point of rendering this traditional power plant classification out of date.

Acknowledging this, the IEA recently proposed a new characterization adapted to modern power systems (IEA, 2018b, p. 34). They propose to introduce an “energy volume” and an “energy option” type of plants by focusing on their evolving role in the system rather than on cost-based categories, which result to be only loosely linked to flexibility attributes of the underlying technology²⁸.

Increasing the flexibility attributes of thermal power plants implies using them in load following mode (see 1), so running them at minimum load levels for longer periods, increasing their utilization in part-load, and cycling them more frequently. Consequently, flexible operations increase the mechanical and thermal stress on components which can lead to higher failure rates and maintenance costs increases with respect to historical levels. Among the key findings of a recent report of Agora Energiewende (2017), assessing the flexibility of thermal power plants is the fact that “improving

²⁶ “Retrofitting the existing large thermal power fleet is considered the fastest way to scale up flexibility in the system. It usually takes 5-6 years to build a pumped hydro station, and 2-3 years to establish gas-fired units. In comparison, it normally takes less than 3 months to retrofit a thermal power plant.” (CEM, 2018, p. 20).

²⁷ Baseload and mid-merit units are being widely dispatched as peak units.

²⁸ That is, some combined cycle gas turbine (CCGT) are not flexible, while other can be if technically designed or upgraded/retrofitted to be. Similarly, old coal plants might not be very flexible but new ones can be flexible enough to accommodate significant amounts of variability.

the technical flexibility usually does not impair the efficiency of a plant, but it puts more strain on components, reducing their lifetime”.

But the impact of cycling on the different components of a plant is closely dependent on the main design of the unit, which makes any attempt of giving accurate cycling costs figures at the technology level very difficult. Lew et al. (2013) proposed to fill this gap by providing lower and upper bounds based on real data collected by APTECH. They show that cycling costs of thermal power plants are led by extra fuel requirements, operation and maintenance costs related to wear-and-tear of components and ramping costs. Furthermore, they elaborate a detailed scenario analysis to assess the potential impact of increasing VRE shares on dispatch and cycling costs of thermal power plants operating in the US Western Interconnection. Assuming average fuel prices of 2013²⁹, they find that increasing shares of variable renewables mainly displaces gas units out-of-the market while emphasizing coal on load following mode. Coal was found to be ramped daily, which is an order of magnitude higher than in scenarios with no variable renewables, and it is shut-down weekly, or less, which represents almost no deviation from a case without variable renewables. They conclude that while increased cycling would put a burden on the economics of coal plants due to maintenance cost, coal plants would still operate within their technical limits in such scenarios, supporting the integration of variable renewables. Moreover, there are many upgrading options to foster their flexibility attributes and/or to decrease the additional costs associated to cycling.

²⁹ Sensitivities on gas prices were also tested by the authors and they conclude that cost of “gas has a much greater impact on system-wide cycling costs than the addition of wind and solar that cycling costs”.

Box 1. The Danish experience

The issue of flexibility supply from thermal power plants has received considerable attention in the last years, and the role of coal-fired power plants is part of the discussion since it represents an important share of thermal capacity in some of EU countries that are experiencing increasing shares of variable renewables³⁰, but also in emerging countries like China and India.

The Danish case³¹ is an illustrative example of a revolution of the role of coal for the integration of variable renewables. Denmark is a frontrunner in wind power deployment and can be considered a reference for assessing the flexibility challenges (see also figure 2). The country has deployed a comprehensive stepwise strategy for unleashing flexibility by enhancing interconnections with neighboring countries, increasing the flexibility of thermal power plants and CHP units, as well as introducing demand-side flexibility and enhancing market and regulatory design.

Even if the Danish coal power plants were initially designed for supplying baseload, they have become the most flexible fleet in Europe (Ea Energy Analyses, 2015). At the plant level, the measures implemented to enhance flexibility attributes include:

- Keeping vital components at a higher temperature during warm starts and updating the control software for including advanced start-up criteria, repowering options, for shortening start-up times;
- Introducing indirect firing strategies, switching from two-mill to single-mill operations, enhancing the control system, adding thermal storage among other engineering upgrades for lowering minimum load levels and enhancing ramping rates;
- Enhancing the monitoring system for allowing operations below the Benson limit³² with active monitoring of the fatigue of components for closely assessing maintenance/replacement needs and/or the re-design of certain components (i.e. wall thickness);

All of those retrofits have been successfully implemented for decreasing the minimum stable load and enhancing ramp rates, while limiting cycling costs overruns³³. As a result, the standard flexibility parameters of Danish coal-fired power plants have achieved state-of-the-art performance during recent years³⁴.

Regarding the integration with the heat sector, the review of the feed-in-tariff scheme for heat supply from CHP units has helped to reduce the incentives of the plants to be dispatched as "must run" units on the electricity market (i.e. a sort of heat bound), thus, disentangling the supply of both services. Furthermore, the addition of thermal storage and electrical boilers is being progressively introduced and incentivized through tax rebates for district heating systems with CHP. This facilitates improved economics as the operators can arbitrage between heat supply from the turbines, the storage or the boilers, depending on the electricity price at a given moment.

In general, the Danish experience in terms of flexibility provision is a case in point for other countries preparing themselves for similar challenges as they expand variable renewables. The most recent examples are those of China (CEM, 2018) and Turkey (Godron et al., 2018; Saygin et al., 2019).

³⁰ Poland and Germany face a significant change in their energy mix at this light. On the contrary, France has developed a large nuclear park during the 80's and is therefore much less concerned by such debate.

³¹ This box is partially based on the findings of a recent study of Ea Analyses (2015) commissioned by Agora Energiewende.

³² The Benson limit refers to the minimum load of the boiler that would allow autonomous water flow on the evaporator.

³³ It is worth noticing that the intervention at the plant level are performed following a technical methodology allowing to identify all the possible enhancements while the timing and magnitude of the refurbishment decisions are assessed under a revenue maximization criterion given the trends of the power market.

³⁴ Similar initiatives have been taken in Germany, where the Moorburg coal plant in Hamburg, as well as the plants in Bexbach and Wesweiler are just some of the examples.

3 Assessing the flexibility provision from coal-fired power plants in Germany

Key takeaways

3.1 The assessment of the contribution of coal-fired power plants to the provision of flexibility in Germany is provided in two stages. The first adopts an historical perspective by analyzing the recent outcomes of 2015 and 2018, as for the official data from ENTSO-E. The second adopts a prospective approach and is a “what-if” analysis based on scenarios and data from DENA and the IEA for estimating the role of coal with increasing renewable energy shares. The Deloitte European Electricity Model (DEEM) is used in both stages for simulating the commitment and dispatch of power units on the market with a focus on coal plants. In every case the analyses start describing the flexibility requirements of the system (demand-side analysis) and then we compute dedicated flexibility metrics on the outputs of coal power plants (supply-side analysis).

3.2 Ambitious energy policy guidelines have led to considerable changes in the structure of the electricity sector. The two key elements over the last twenty years were certainly the phase-out of nuclear power and the Renewable Energy Sources Act. Renewable power generation capacity increased from 12 GW in the year 2000 to 37.8 GW by the end of 2008 and to 118.3 GW by the end of 2018. Nuclear capacity is expected to be completely phased-out by 2022. Regarding the development of coal capacity, two waves of investments can be distinguished. The first, belongs to the investments made during the 1970’s and 1980’s when the core of the existing capacity was built; the second wave, between 2013 and 2016, consisted of the refurbishment and/or expansion of aging units, as well as the construction of new flexible and more efficient units.

The renewable energy shares in Germany for 2015 and 2018 were 32% and 38% respectively. At such levels, we observe that a considerable amount of variability starts impacting the system as it can be seen by the deformation of the load duration curves for both years, although, the ramp duration curves are only slightly affected. Our results confirm IEA’s current classification for Germany as belonging to the integration phase 3 (see also figure 2), in which “renewables determine the operation pattern of the system”. Nevertheless, there is just little difference between the metrics for 2015 with respect to 2018, since the relative increase of renewables was modest. Consequently, we find that coal-fired power plants contributed markedly to the integration of renewables in both years with unit-based flexibility metrics evolving with the same order of magnitude of the variable renewable energy increase.

3.3 The prospective study considers DENA’s capacity projections for the decades to come which results in approximately 50%, 60% and 70% renewable energy shares. Such contrasted scenarios show a marked transformation of the system, evolving through integration phases 4 and 5. Renewables make up for more than 100% of net demand during several days per year. Ramping episodes become steeper and longer (“short-term flexibility” requirement). Also, there are periods with energy deficits lasting for several days (“mid-term flexibility” requirement). The main determinant of the market is the infeed from renewables. The proposed metrics, accounting for the provision of “short term” and “mid-term” flexibility from coal plants, suggest that coal units are able to safeguard the integration of renewables.

3.1 Framing the quantitative analysis

The Deloitte European Electricity Market Model (DEEM) is an in-house model used to simulate the development and behavior of European electricity markets. It is a mixed-integer optimization model

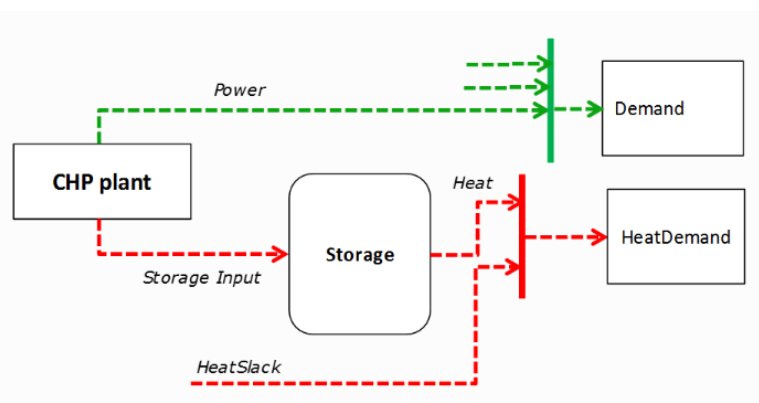
that allows for reproducing the commitment and dispatch of power generation units, as well as for performing prospective studies on the evolution of dispatch and installed capacities of power systems. The model is based on an hourly optimization of the entire EU and considers exchange and operating constraints at the unit level. It is particularly tailored for assessing the integration challenges of variable renewables and flexibility provision.

Modelling assumptions

For this study, DEEM has been set up for evaluating the flexibility needs in Germany with a focus on coal-fired power plants. The analytical design comprises a historical assessment focusing on the years 2015 and 2018, and a prospective assessment, looking at the official renewable expansion targets in the years to come. General assumptions include:

- A strict balance between power supply and demand must be kept at every hour. For historical years, time series of import/export power flows have been used to compute the German domestic load. For the prospective study, and because of the increasing share of renewables, neighboring countries have also been modeled to take into account possible power flow variations on cross-border interconnectors.
- Renewables can be curtailed if needed in periods of oversupply. This allows the model to benefit from the full capabilities of renewable generation, without forcing it to install batteries to store the spilled energy. Nonetheless, as we are conducting an economic optimization analysis, the model has no incentives to curtail renewable generation, as their marginal cost of production is zero and the simulations are conducted under a cost minimization objective⁴⁰.
- CHP plants have been modeled in a stylized way⁴¹. Two types of technologies have been considered: back-pressure turbines and extraction turbines. Data comes from (Danish Energy Agency, 2016) and (DIW, 2017) for Power-To-Heat factors, CHP technologies and installed capacities. Thermal storage is made possible on an aggregated manner, thus allowing for some flexibility on the heat balance coming from thermal inertia. Additionally, heat can also be provided by a "heat slack" (see figure 9) representing an auxiliary source of heat from a secondary fuel.

Figure 9. Representation of CHP technology in DEEM



Source : (QUOILIN Sylvain et al., n.d.)

⁴⁰ The value of RE infeed is given by the cost of the marginal unit they offset (e.g., mainly operating costs of mid-merit units). This value is higher than the savings obtained due to avoided wear and maintenance after curtailment. Thus, under a cost minimization strategy, the infeed of RE is often maximized and curtailment is left only to episodes where there is oversupply.

⁴¹ The representation of CHP units are based on the Dispa-set model of the JRC.

DEEM accounts for all the operating constraints of thermal power plants, cross border exchanges and scheduling of hydro power plants. Regarding the technical parameters, the model considers start-up and shut down constraints, part-load operations, upward and downward ramping capabilities, minimum and maximum power output, minimum up and down times, as well as start-up costs per operating unit (as explained in section 2.2).

Flexibility metrics

Flexibility requirements are present along the three fundamental dimensions of power systems, namely the energy, the capacity and the ramping. These three dimensions are linked by integration and differentiation operations⁴². Thus, the ramping and capacity dimensions can be associated under the notion of “short-term” flexibility which in the scope of this study refers to the hourly capacity levels and ramps. The capacity and energy dimensions are combined on the notion of “mid-term” flexibility which on the scope of this study refers to periods of several days of duration (i.e. one to seven days). Hence, we propose three metrics for capturing the contribution of coal-fired power plants to the provision of “short-term” flexibility and a parametric study for assessing role in providing “mid-term” flexibility.

We define the average ramping metric (AR) as the total ramps done by the coal-fired fleet over total generation. The average unit ramping (AUR) metric focuses on an individual power plant level. This metric enables us to assess the relative share of ramping compared to the total yearly production as for the Average Ramping metric, and levelized by the number of units in the scope. The advantage of such metrics is that they integrate the fact that the increasing share of renewables will necessarily reduce the total annual output of coal power plants, as coal will be pushed progressively out of the merit order when renewable infeed is high. It is also important to account for the number of units, as the more units we have for a same ramping need, the lower the ramp is for an individual power plant, justifying the need for the second metric.

$$AR = \frac{\sum_{Hours} |Production_{coal}(hour) - Production_{coal}(hour - 1)|}{\sum_H Production_{coal}(h)}$$

$$AUR = \frac{AR}{Units_{coal}}$$

The mean cycling factor (MCF) is defined to capture the cycling dimensions of coal-fired power plants over the course of the year. Therefore, the number of changes of the commitment state (i.e. start-ups plus shut-downs decisions) per year is included as the third metric for the assessment.

$$MCF = \frac{\sum_{Hours} |UnitCommitted_{coal}(hour) - UnitCommitted_{coal}(hour - 1)|}{Units_{coal}}$$

As previously explained, the power and energy dimensions of flexibility are mainly relevant at the tails of the distribution of the net load curve that stand for very few hours per year (i.e., hours during which load is relatively high and infeed low or hours during which load is relatively low and variable renewable infeed high). Regarding coal-fired power plants, only the capacity scarcity periods (i.e. the left tail of the net load duration curve) are relevant since coal plants can only provide positive capacity. The extent and length of the scarcity episode will determine the power and energy capacity provided respectively. Such scarcity periods are typically denoted “dark winter doldrums” or “cold dark doldrums”, essentially referring to periods of time when the sun does not shine, the wind does not blow and there is a significant electricity demand level to be met.

⁴² Ulbig and Andersson explain that such metrics “exhibit the so-called double integrator dynamics: energy is the integral of power, which in turn is the integral of power ramp-rate. Due to their inter-temporal linking, the three metrics constitute a flexibility trinity in power system operation” (Ulbig and Andersson, 2015, p. 157).

The duration and the frequency of cold dark doldrums are key: they occur regularly for a few days but, in rare occasions, may possibly extend over weeks. Being prepared for such weather phenomena becomes critical when variable renewable energy shares are high since otherwise there is a risk that the remaining capacity (i.e. other capacity than variable renewables) might not be sufficient for balancing demand throughout the duration of the doldrums. Hence, an assessment of such periods complements the prospective analysis. In this case, the flexibility provision of coal-fired plants is determined by analyzing whether their energy shares during such periods significantly exceeds their yearly average values.

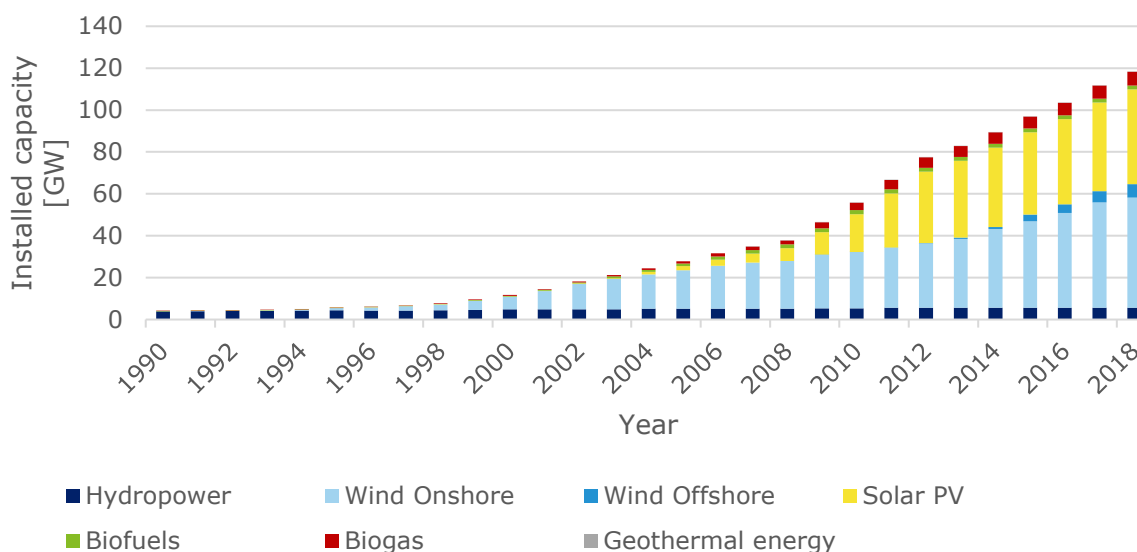
3.2 The historical perspective

3.2.1 The electricity market and the energy transition

Germany is, with electricity consumption of some 600 TWh per year and 214 GW of installed power generation capacity, the biggest power market in the EU. The German power market is particularly well interconnected with neighboring systems (22 GW of importing capacity and 16 GW of exporting capacity) and Germany is a net exporter of electricity (in 2018, net exports amounted to 46 TWh). Ambitious energy policy guidelines have led to considerable changes in the structure of the electricity sector. The two key elements over the last twenty years were certainly the phasing out of nuclear power and the uptake of renewable energy.

Concerning nuclear energy, there have been multiple policy turnarounds. In 2001 a nuclear phase-out plan was implemented by law. Then, in 2010, the Energy Concept of the federal government reconsidered the nuclear phase out decision from 2001 and allowed for a lifetime extension of the nuclear fleet. The argument was that nuclear energy is a cost-effective and low-carbon bridge to a renewables-based economy. On average, an additional 12 years of lifetime were granted, extending the fleet's operations until the mid-2030s. The Fukushima-Daiichi accident was another turning point: the government decided an accelerated and definitive phase-out of nuclear energy within weeks after the accident – this has become a cornerstone of the so-called 'Energiewende'.

The main instrument to make renewable energy the backbone of power supply is the Renewable Energy Sources Act (Erneuerbare Energien Gesetz - EEG). At its inception, this law guaranteed renewable energy sources a feed-in tariff for a period of 20 years after the commissioning of the plant. Grid operators are obliged to purchase the renewable electricity and grant priority access to the grid. The trading companies pass on the financial deficit – feed-in tariff minus market price – to end users by imposing a surcharge. Renewable power generation capacity increased from 12 GW in the year 2000 to 38 GW by the end of 2008 and to 118 GW by the end of 2018 (Figure 10). In particular the capacity of solar PV soared after 2007 because the costs of the installations were below the feed-in tariff. Within the last ten years – between end of 2008 and the end of 2018 – 39 GW of solar PV and 36 GW for wind power were added to the system. The share of renewables in total electricity generation climbed from less than 7% in 2000 to about 38% in 2018. Accounting for 70% of renewable electricity generation in 2018, variable sources like wind and solar are dominant.

Figure 10. Evolution of renewable electricity generation capacity in Germany

Source : Federal Ministry for Economic Affairs and Energy (2019)

Prospectively, major policy aspirations are the conversion from a fossil-based to a renewables-based energy system and a concurrent reduction in energy consumption via increased energy efficiency. In terms of long-term decarbonization targets, the cornerstones of the German 'Energiewende' are:

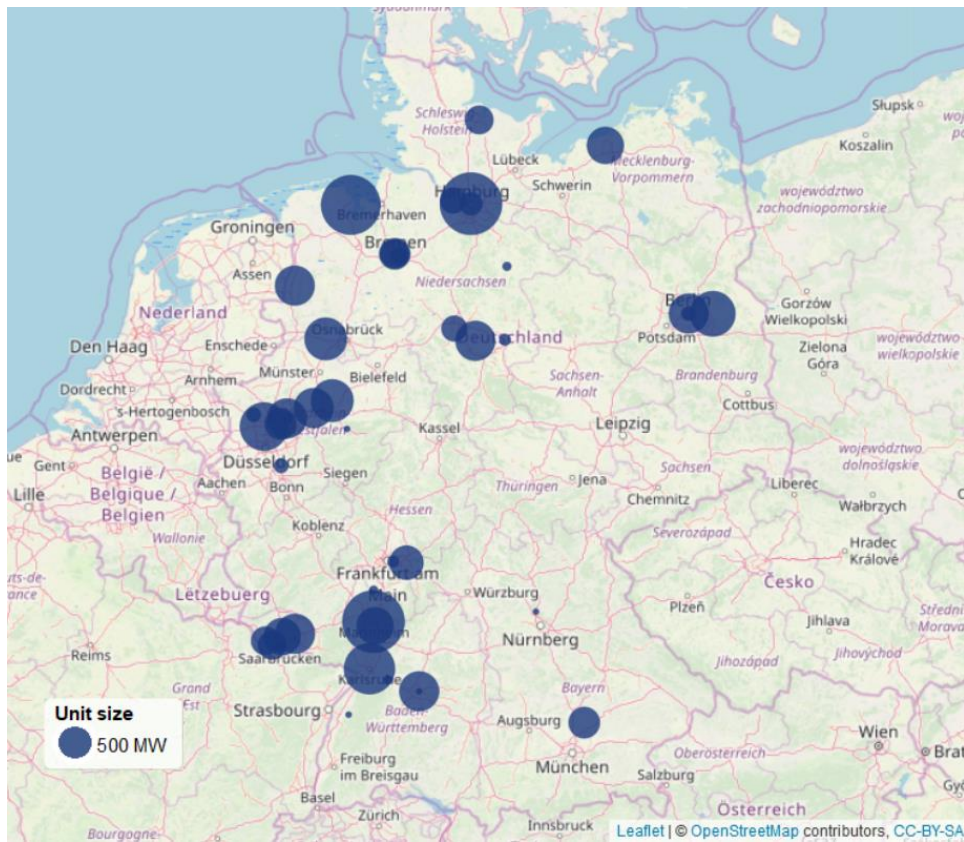
- A reduction in greenhouse gas emissions by 40% by 2020 and 80% to 95% by 2050, compared with 1990 levels
- An increase in the share of renewable energy in total energy consumption to 30% in 2030 and to 60% in 2050
- An increase in the share of renewable energy in total power consumption to 80% in 2050.
- A cut in the consumption of primary energy by half by 2050 compared with 2008 levels.

In light of these objectives, the role of coal and lignite for power generation have been subject to debate. In early 2019 the so-called 'Coal Commission' has recommended a phase-out of coal and lignite from power generation by 2038 and ever since, the government has been working on the details and the practical implementation of this recommendation. It is in this context that we are assessing whether and to what degree coal-fired power plants are technically able to safeguard the integration of ever-growing shares of variable renewables.

3.2.2 The coal-fired power plant fleet at a glance

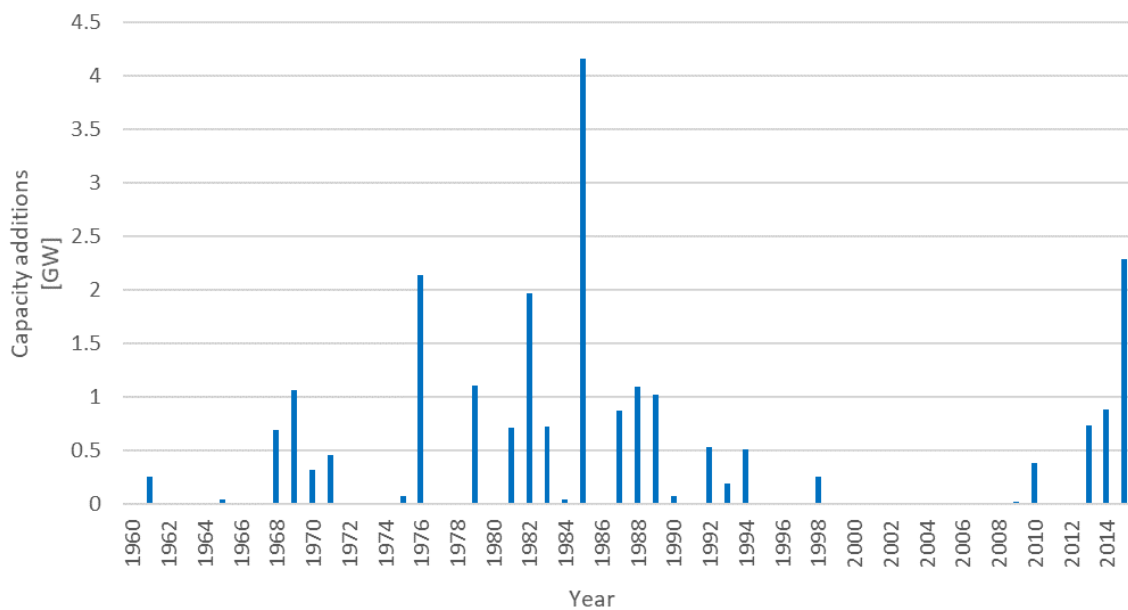
Coal is a major source of electricity generation in Germany, accounting for 12% of total output in 2018. In total there are 24 GW of coal-fired power plant installed at end-2018. Coal-fired power plants are mainly concentrated in the west of Germany, close to the coal fields of North Rhine-Westphalia and the Saarland (Figure 11). Domestic coal production has long been in decline and, with the closure of the last German coal mine in 2018, coal mining has ceased, and Germany entirely relies on imported coal. Although large units exist, with capacity exceeding 800 MW, the average unit size is smaller, at around 200 MW.

Figure 11. Location of coal-fired power plants in Germany



Source : OpenStreetMap and own elaboration

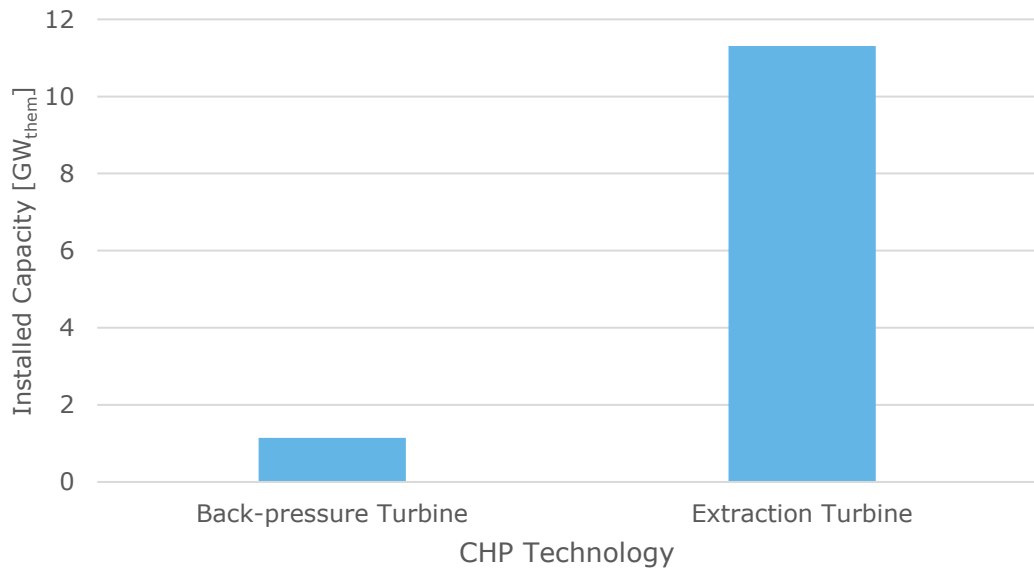
Figure 12. Coal-fired capacity additions and year of commissioning



Source : Own elaboration(DIW, 2017)(DIW, 2017)(DIW, 2017)

Many of those units also provide heat for industrial use and district heating. Heat demand for such units are usually difficult to obtain or estimate, as the heat network is local and there exists no country-wide market for heat. The shares of the two types of CHP plants introduced in section 2.1 are displayed in figure 13 : there is a clear domination of steam extraction turbine over back-pressure turbines.

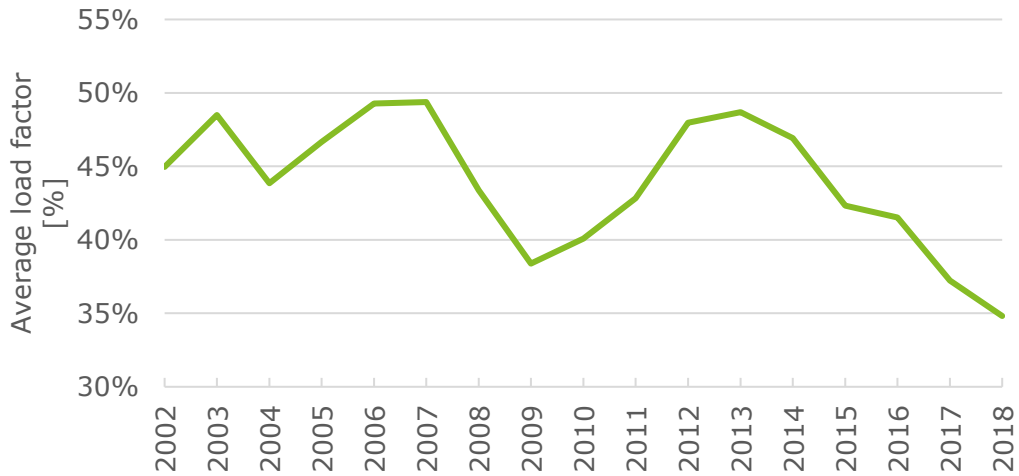
Figure 13. Distribution of CHP technology in Germany



Source : (DIW, 2017)

Despite the strong increase of renewables and their contribution to electricity supply, the average load factor of coal-fired power plants remained in a range between 45% and 50% between 2002 and 2014 (figure 14). This can be explained by an increase in electricity demand in that period. Clearly, outliers are the years 2008 to 2011 when electricity generation dropped as a consequence of the economic crisis. However, after those years the load factor of the coal-fired fleet rebound to historical levels. After 2014 the load factor started dropping, falling to 35% in 2018. As electricity consumption levelled off and renewables increased their contribution, coal-fired plants got increasingly displaced from power generation during that period.

Figure 14. Evolution of the average load factor of coal-fired power plants in Germany

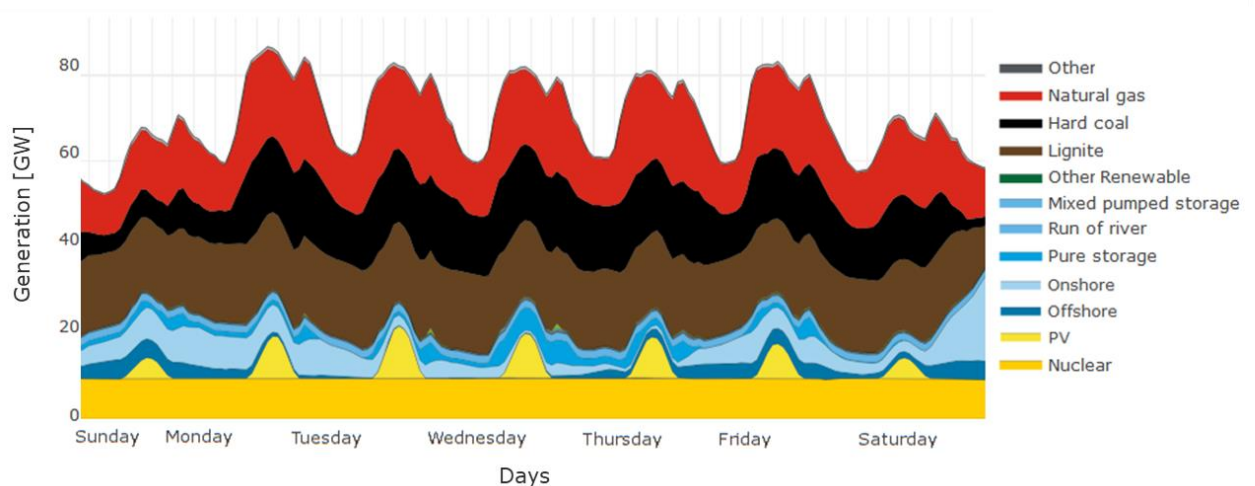


Source : Own elaboration, based on Fraunhofer energy charts

3.2.3 Methodology of the simulations

The historical perspective is based on the official data from the ENTSO-E Transparency Platform⁴³, allowing us to reproduce the historic dispatch with the DEEM model. We selected the years 2015 and 2018 for the assessment. The years were chosen to obtain a maximum difference in renewable energy share (32% in 2015 vs. 38% in 2018) while still having a complete set of power market data available for model validation (data prior to 2015 is incomplete, notably regarding hourly infeed of wind and solar power). By reproducing the historical dispatch we are able to simulate how coal-fired power plants responded to ramping needs by modulating their infeed and increasing their cycling.

Figure 15. Dispatch of an illustrative week in Germany using DEEM (2018)⁴⁴



Source : Own elaboration

⁴³ The ENTSO-E publishes open access data on their platform: <https://transparency.entsoe.eu>

⁴⁴ 'Other' contains power plant with only little installed capacity such as: oil and other fossil power plant not identified as coal, gas or lignite. 'Other renewables' contains biogas, renewable waste, battery and geothermal.

Figure 15 illustrates the dispatch resulting from a simulation of DEEM. Once accounted for must-run generators such as wind or solar, the optimization activates the least-cost generation units to meet demand. The figure shows an illustrative week starting on a Sunday, where weekdays and weekends can be depicted by the level of the load displaying five consecutive peaks (i.e. from Monday to Friday) with lower maximums on the extremes (i.e. during Sunday and Saturday). During this week, every day is composed by two peaks and two troughs. The peaks occur at mid-day and in the evening when residential electricity consumption is high, whereas the troughs correspond to lower afternoon and night loads. Also, output from solar PV follows a distinct bell-shaped pattern as it ramps up in the morning and ramps down during the afternoon. It is also possible to highlight from the figure the less predictable pattern of onshore and offshore wind, subject to seasonal effects but not to a daily pattern such as PV. The infeed of nuclear and lignite plants is essentially flat since they are, due to their low marginal costs, dispatched first, followed by coal and gas, supplying the remaining electricity needed to meet demand. The simulations of both years take into account the historical fuel and CO₂ prices (table 1), and key technical characteristics of power plants (table 2). The simulations were done for the entire year using hourly timesteps.

Table 1. Cost assumptions of the historical analysis ⁴⁵

Year	CO ₂ [€/t CO ₂]	Gas [€/MWh]	Oil [US\$ barrel]	Coal [US\$/t]
2015	7.6	19.7	52.4	59.0
2018	15.7	22.3	71.6	91.6

Table 2. Technical parameters of German power plants ⁴⁶

Fuel	Technology	Vintage class ⁴⁹	Min Up Time [h]	Min Down Time [h]	Start-up costs [€/MW]	Min Power Output [%Capacity]	Max Ramping Up ⁴⁷ [%Pnom/min]	Max Ramping Down ⁴⁸ [%Pnom/min]
Biogas	-	-	0	0	24	20	6	6
Biomass	-	-	2	2	36	20	0.7	0.7
Coal	-	V1	7	3	32	34	0.8	2
Coal	-	V2	7	7	48	27	1.5	3
Coal	-	V3	3	3	35	20	4.5	4.5
Lignite	-	V1	7	7	58	60	1	2
Lignite	-	V2	7	7	58	48	1.5	3
Lignite	-	V3	7	7	58	35	4	4
Gas	OCGT	V1	0	0	35	50	8	8
Gas	CCGT	V1	1	1	53	50	2	2
Gas	OCGT	V2	0	0	35	35	12.5	12.5
Gas	CCGT	V2	1	1	53	40	4	4
Gas	OCGT	V3	0	0	35	20	15	15

⁴⁵ Sources: Based on Capital IQ & ICE

⁴⁶ Data comes from Schill et al. (2017), *Start-up costs of thermal power plants in markets with increasing shares of variable renewable generation*, Nature Energy; Agora Energiewende (2017), *Flexibility in thermal power plants*; and Deloitte analysis.

⁴⁷ Minimum ramp up and minimum ramp down rates are converted and modelled as ramp rates per hour.

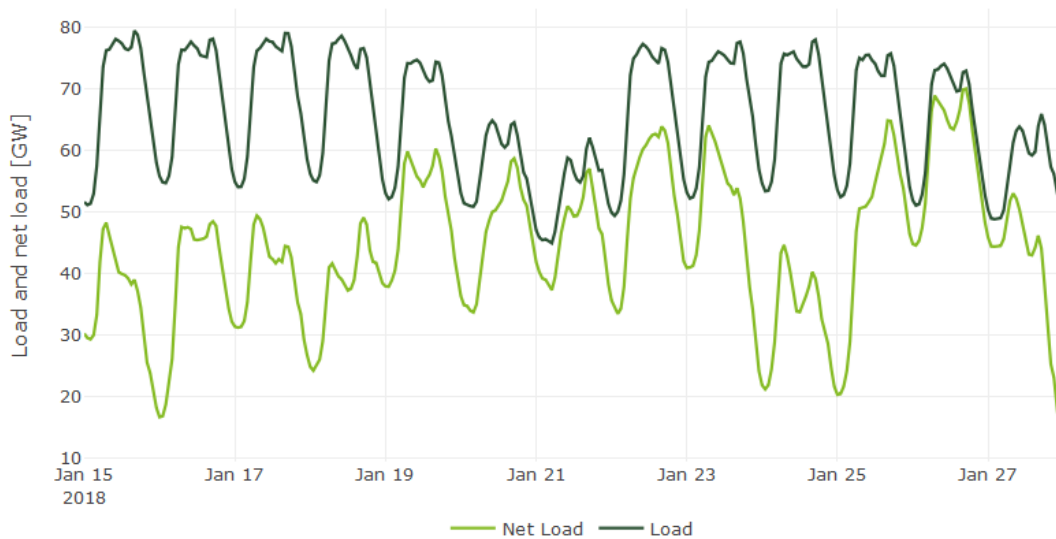
⁴⁸ Vintage class: Power plants with a commissioning year before 1980 are assigned to vintage class V1, plants with a commissioning year between 1980 and 2000 are assigned to V2 and all plants commissioned after 2000 are in class V3.

Gas	CCGT	V3	1	1	53	30	8	8
Nuclear	-	-	10	10	50	50	0.5	0.5

3.2.4 Insights from 2015 and 2018

It is illustrative to highlight the differences between load and net load using data for two selected weeks in January 2018 (Figure 16). Although the correlation between the two time-series is moderately positive (0.58 in 2018), net load, i.e. the electricity demand that needs to be served by dispatchable power plants, is more volatile and includes steeper ramps and larger differences between peaks and troughs than the actual load. Nevertheless, the day and night electricity demand pattern remain recognizable by the consecutive peaks and troughs of the curves. The typical morning and evening peaks as well as the workday/weekend pattern are however widely distorted, emphasizing the role of variable renewables a key driver for the operations of dispatchable power plants.

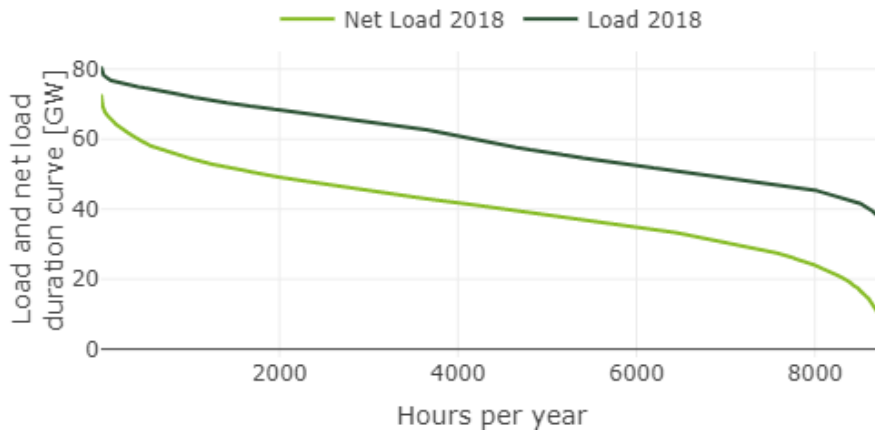
Figure 16. Load and net load of a selected two-week period in January 2018



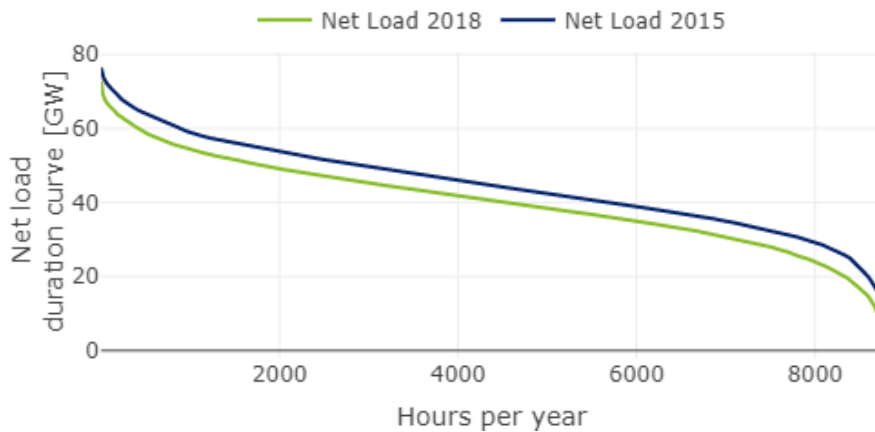
Source : Own elaboration

This also puts pressure on the market design and regulatory framework in place to evolve for ensuring the necessary incentives to market participants so they breakeven under those changing conditions (fewer full-load hours and more hours at part and peak load).

Figure 17. The impact of variable renewables on load duration curves and its evolution between 2015 and 2018



a) Load and net load comparison for 2018



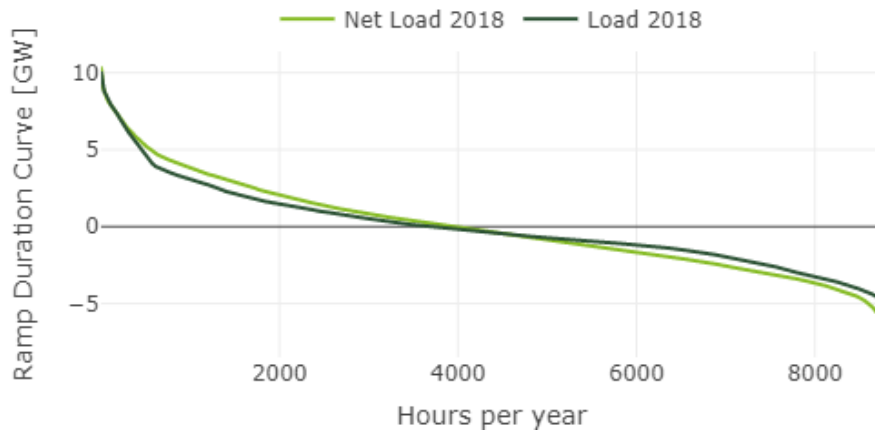
b) Net load evolution between 2015 and 2018

Source : Own elaboration

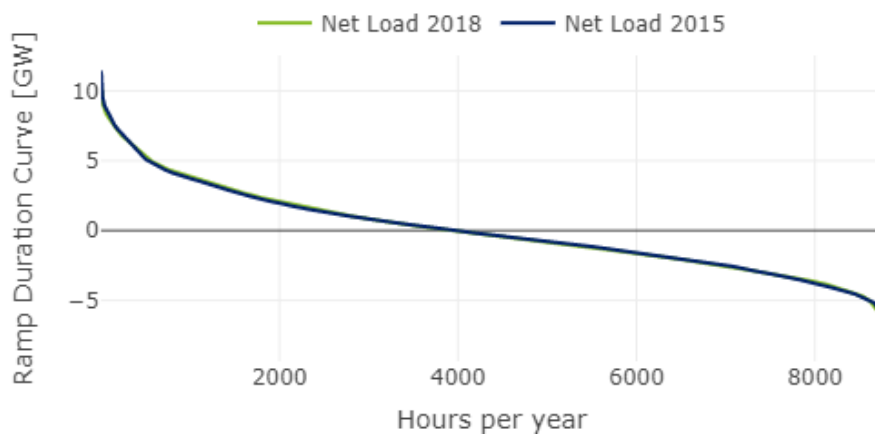
Figure 17.b illustrates the evolution of the net load duration curve between 2015 and 2018. As the installed capacity of renewables and their output increased⁵⁰, the net load duration curve is shifted downward between 2015 and 2018 (i.e. the centre of the 2018 curve is around 3.5 GW below the 2015 curve). With total electricity demand staying at similar levels between the two years, the share of coal and gas plants in the electricity mix declined. It is noteworthy that the additional deployment of wind and solar power contributed relatively little to reducing peak load (i.e. the left tail of the 2018 curve is only around 1 GW lower than the 2015 curve).

⁵⁰ The total wind plus solar capacity in 2015 was 82 GW and went up to 102 GW in 2018; regarding their infeed, the total wind plus solar energy generation in 2015 was 111 TWh and increased up to 148 TWh in 2018.

Figure 18. Effect and evolution of variable renewables on hourly ramps durations



a) Comparison between load and net load



b) Evolution of net load ramps

Source : Own elaboration

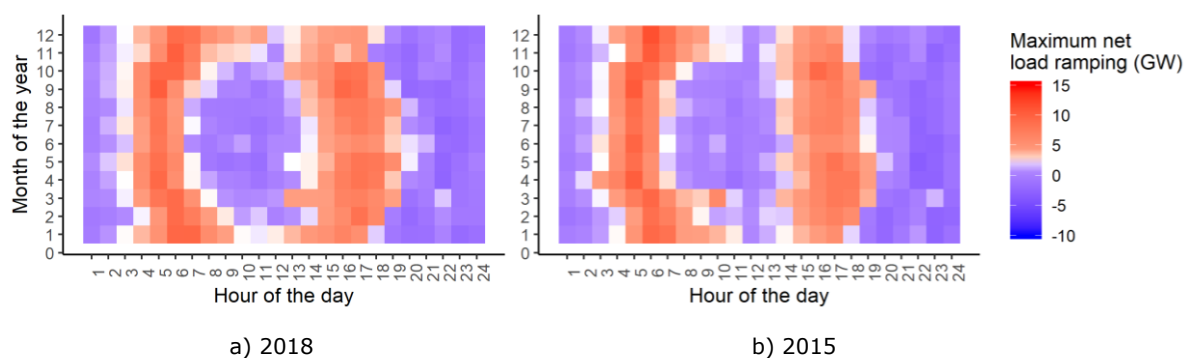
The same approach is used to assess the evolution of ramping needs. Figure 18.a demonstrates that upward (i.e. positive) and downward (i.e. negative) ramps are amplified by growing shares of variable renewables. It means that dispatchable units need to accommodate more frequent and steeper ramps than they would have to without infeed from variable renewables.

The overall fluctuation of the net load is the result of combining the variations of demand with those of the variable infeed from renewables. At the current levels of wind and solar penetration both types of variations have similar weights over the total system variability (i.e. variable renewable integration phase 3). The individual effects on the swings can be additive (if they go on the same direction) or neutralizing (if they go on the opposite direction). In 2015 the volatility of demand was higher than in 2018, while total variability of wind and solar was slightly smoother⁵¹ in 2015. As a result, there is very little difference between the net load ramp duration between both years (figure 18.b). This is also due to the relatively modest increase of wind and solar penetration between 2015 and 2018 (i.e. only +6%-points). More contrasted scenarios (i.e. comparing two different integration phases)

⁵¹ Such inter-year variations are also weather dependent.

and/or analyzing higher levels of variable renewable penetration would lead to wider differences between the ramp duration curves.

Figure 19. Hourly net load ramps across the year



Source : Own elaboration

Describing the timing and duration of ramping episodes is also key for understanding the evolution of the flexibility requirements. Figure 19 shows the distribution of ramps across the year for each hour and within each month. Over the course of a day, dispatchable power plants need to ramp up twice to serve net load: in the morning between 4-8 am and in the afternoon between 3-6 pm. These periods are followed by negative ramping periods of lower magnitude and duration. In the afternoon negative ramp episodes last around 3 hours to 4 hours, and more pronounced negative ramps occur during the night. Even if there is no significant difference between 2015 and 2018, the resulting daily pattern is similar to that of the early days of the Californian “duck chart” (see figure 5) independent of all structural and contextual differences between both power systems. Seasonality affects only the timing of the ramps within the day but not their magnitude. Maximum net load ramps are always approximately the same, regardless of the season, but there is a shift in time regarding when it happens.

Table 3. Flexibility metrics in 2015 and 2018

Year	Renewable share	AUR	% Change	AR	% Change	MCF	% Change
2015	31.5%	0.88		5.98		39.13	
2018	37.8%	0.92	4.20%	5.78	-3.35%	41.0	4.78%

The differences between the flexibility metrics calculated for 2015 and 2018 are minor (table 3). In terms of share of gross electricity consumption, renewables have accounted for 32% and 38% in 2015 and 2018 respectively (Federal Ministry for Economic Affairs and Energy, 2019). Although this is a significant increase in the share of renewables within three years, the market fundamentals and thus the flexibility needs remain similar in the two years. As a result, the values of the metrics stay in the same order of magnitude and only show minor differences. This is in line with IEA’s assessment that Germany is currently in phase 3 of variable renewables integration.

Due to the merit-order effect and other market factors evolving against coal plants (see table 1), coal has indeed a less favorable situation in 2018 than in 2015. In fact, those years have seen the

profitability of coal plants decreasing against other thermal technologies, as both the CO₂ price (+106%) and the coal price (+55%) have shown large increases compared to gas (+13%), which makes the competition harder. We notice a decrease of -3% on the Average Ramping metric between 2015 and 2018 that is explained by a slight decline in hourly ramps with respect to the total generation of coal plants. One could therefore be tempted to think that coal-fired plants have ramped relatively less when only regarding their energy contribution. However, we would miss an important point, which comes from the fact that the number of coal units has decreased between both years: the installed capacity has decreased from 26,5 GW in 2015 to 24,6 GW in 2018 due to 23 units having been retired against four newly built. Therefore, when looking at the unit level metrics, the Mean Cycling Factor and the Average Unit Ramping, both show a slight increase of around 4%. As the total number of coal-fired dispatchable units has declined, we can conclude that the remaining units have run in a slightly more flexible way than before.

The evolution of coal plant dispatch between 2015 and 2018 is therefore twofold: first, the yearly generation from fossil fuels, and more especially coal, is decreasing as more renewables are entering the market (320 TWh from fossil fuels in 2015 dropping to 301 TWh in 2018 as for ENTSO-E⁵²), therefore decreasing the overall market shares of coal. Second, the individual power plants cycled and ramped more than before. The coal-fired power plants in Germany were however still able to take their shares by running more flexibly at the unit level, as the metrics confirm.

Yet, as previously commented, the percentage change on the metrics display only very little variations due to the – from a system perspective – still moderate levels of wind and solar penetration (31.5% and 37.8%, corresponding to integration phase 3), and the modest – again from a system perspective – increase between the two years (+6.3%-points).

These results suggest that the dispatch of coal-fired power plants have been effectively adapting to an evolving market context with rising price volatility introduced by variability and uncertainty of renewables. The following section aims at verifying these findings by introducing a prospective assessment of the role of coal plants under more ambitious renewable energy shares and provides further insights on the provision of flexibility.

3.3 A prospective view

3.3.1 Methodology of the simulations

Three different renewable energy penetration levels are assessed – 50%, 60% and 70% in terms of share of domestic electricity generation – to evaluate the impact of rising variable renewable energy deployment on the role of coal plants in Germany. This part of our study aims at analyzing the effect of increasing shares of renewables on the system and the extent to which coal plants could help accommodating their variability.

As for the “what if” analysis, fuel costs are assumed the same than those of 2018. Consistent with DENA (2019), we account for the expected evolution of CO₂ prices⁵³ based on the World Energy Outlook’s New Policies Scenario (IEA, 2018c); the installed capacity of variable renewable energy technologies in Germany has been calibrated as for projections provided by DENA (2019)⁵⁴ (table 4). As such, we focus on the effects of increasing the variable renewable shares on coal plants and isolate

⁵² The only exception is fossil gas that goes from 53 TWh to 87 TWh between 2015 and 2018. Further figures are available at: https://docstore.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs2015_web.pdf; and https://docstore.entsoe.eu/Documents/Publications/Statistics/Factsheet/entsoe_sfs2018_web.pdf.

⁵³ The CO₂ cost in Europe are determined by the emission cap applied on the EU-ETS, which are regulated by EU authorities.

⁵⁴ Also, according to DENA’s considerations, the nuclear capacity in Germany is assumed to be completely phased-out at the levels of variable renewables assessed.

these effects from external factors and issues still under debate such as energy policies from neighboring countries (e.g. nuclear phase-out in Belgium or Switzerland, renewable energy targets, etc.), increasing interconnection capacity, among others. Hence, it is a typical “what if” scenario analysis.

Table 4. Assumptions used for prospective study in Germany

Renewable energy shares in Germany* (% of yearly production)	Solar PV capacity [GW]	Wind Onshore capacity [GW]	Wind Offshore capacity [GW]	CO₂ prices [€/tCO₂]
50%	73	71	11	25
60%	91	82	17	31
70%	97	91	23	37

* These shares of renewables also include other non-variable sources such as hydro and geothermal but are mainly composed of wind and solar.

Source : DENA, WEO2018

For this prospective case, the following modifications have been implemented in the model:

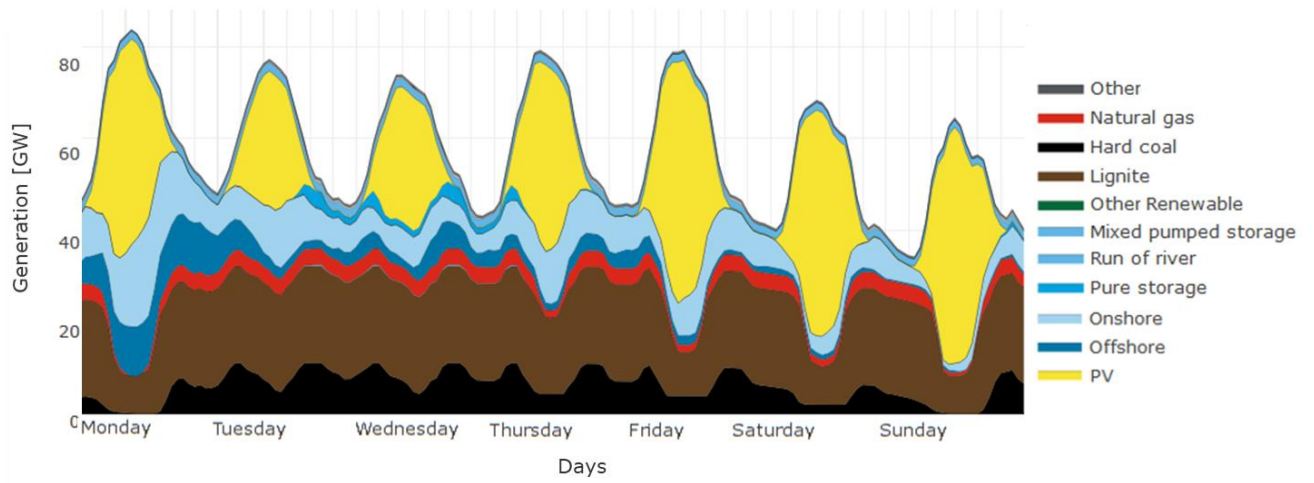
- The representation of neighboring countries was enhanced by not only simulating the dispatch of plants within Germany but also considering the dispatch decisions of adjacent countries. Based on this, we determine cross-border electricity exchange.
- We include for power plant availability figures (e.g. failures, maintenance, etc.) based on the historical patterns and assumed similar values for the prospective analysis. However, when it comes to coal power plants and other thermal technologies, their dispatch is more affected by market determinants and technical capabilities than by unavailability.
- We implemented a clustering algorithm to identify representative weeks, following Nahmmacher et al. (2016). As described in section 3.3.3, a critical week (cold dark doldrums) is also considered. All results are then extrapolated according to the weight of the clustering algorithm.⁵⁵

3.3.2 Assessing a power system with large shares of variable renewable energies

The impact of a high expansion of wind and solar generation (+22%-points compared to 2018) is illustrated in figure 20. It shows an illustrative week for Germany with 60% of renewables (mainly composed of wind, at 35% and solar, at 16%). It can be seen how coal-fired power plants are not anymore dispatched for baseload but are rather used to complement the generation from wind and solar, resulting in very pronounced dispatching ramps and periods of almost zero production when there is strong output from wind and solar (see Monday and Sunday in figure 20)

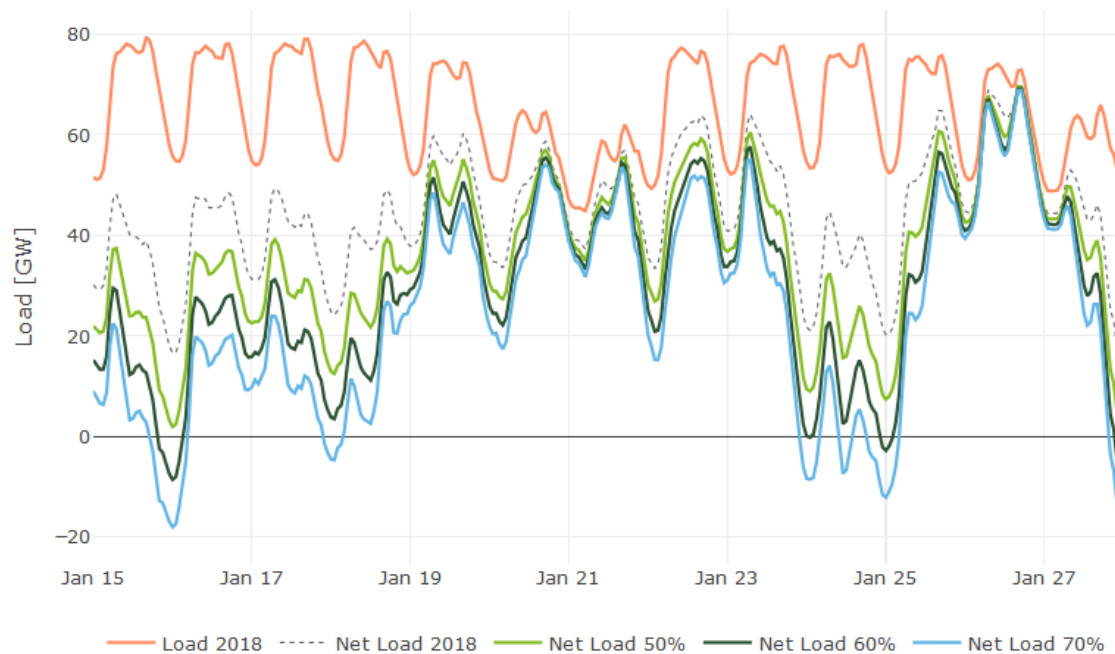
⁵⁵ The identification of representative weeks is a common practice in modelling. Reducing the studied timeframe allow to add more refinement in key aspects of the model, and these without losing accuracy of the results. We therefore included for this study the 12 most representative weeks of the year, plus the most critical one in terms of mid-term flexibility (accounting for low frequency high impact events).

Figure 20. Illustrative dispatch on a selected week of July (60% share of renewables)



Source : Own elaboration

Figure 21. Load and net load curves of a selected week with different shares of renewables



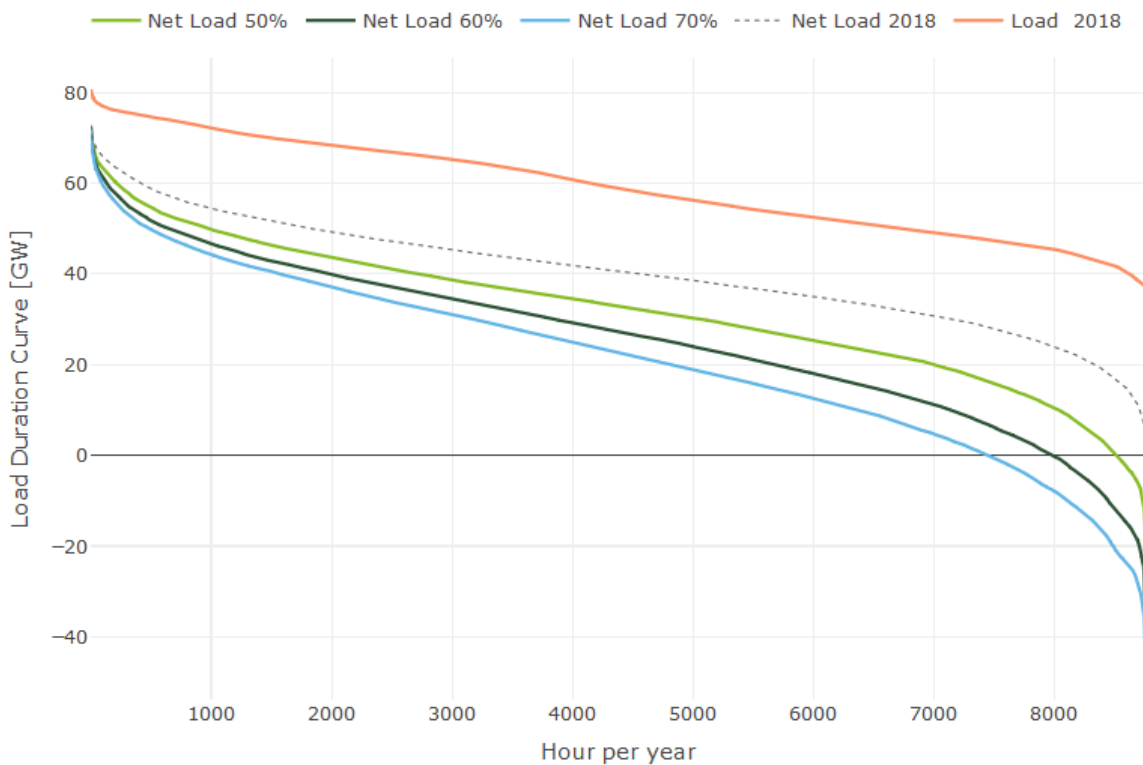
Source : Own elaboration

We can see that, in the selected weeks, for renewable energy shares of 60% and above, there are periods during which the total available generation from renewables exceeds demand. If this excess electricity cannot be stored by the power system, it needs to be curtailed. In contrast, on January 26th, we can see that independent of their share, output from renewables is negligible, implying a strong call on dispatchable power plants to meet the electricity demand.

Assessing the net-load duration curves for the entire year confirms that indeed, increasing the share of renewables hardly reduces net load during peak hours (see top-left tail of figure 22). During the

hours of highest net load, more than 69 GW of dispatchable generation capacity are needed to keep the lights on, no matter how much wind and solar power is installed. This illustrates the fact that dispatchable power plants remain key for ensuring security of supply of the system even if most of the annual electricity generation comes from renewable sources. Consequently, an increase in variable renewable generation capacity does not necessarily allow for significant closures of dispatchable plants.

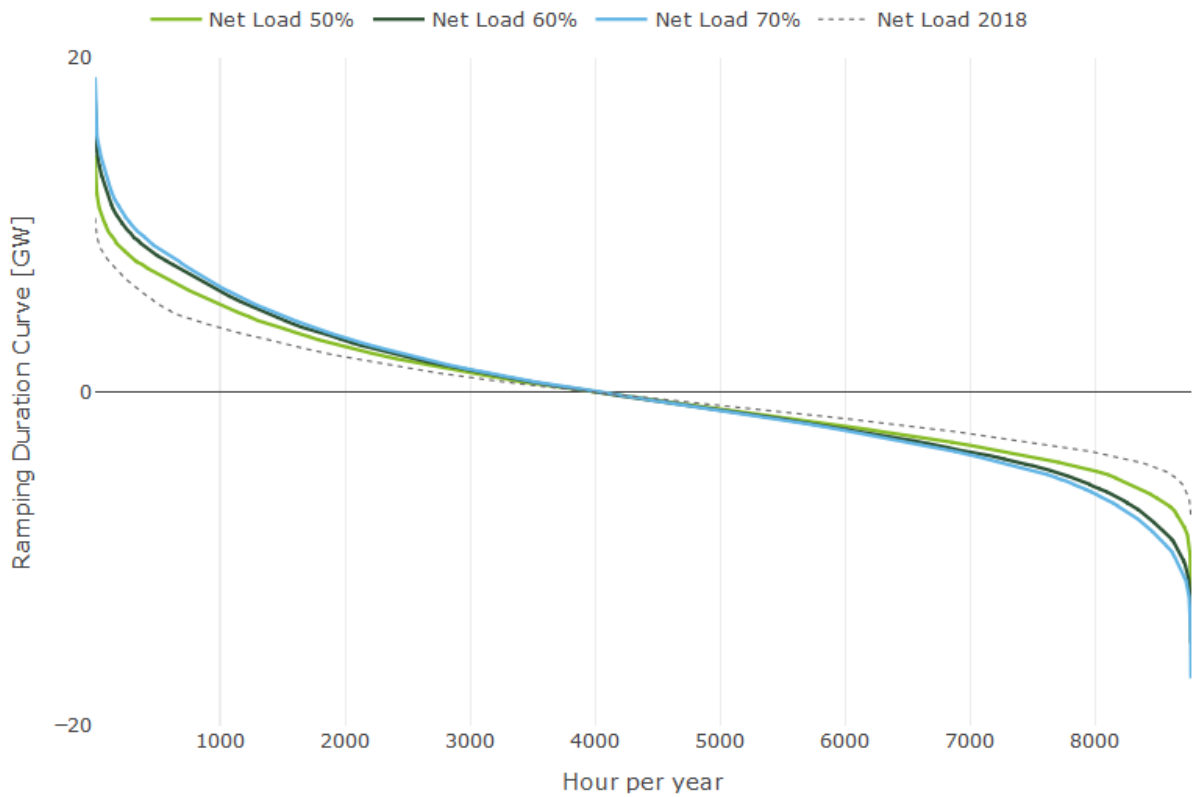
Figure 22. Effect of variable renewables on load duration curves



Source : Own elaboration

In contrast, increasing the shares of renewables amplifies the oversupply of electricity during certain periods (see tails on the bottom-right of figure 22). For instance, a share of 60% of renewables implies that during nearly 10% of the hours of a year, i.e. the equivalent of more than one month, more electricity is generated than consumed. The reason for this is the strong correlation of generation from wind and solar plants in Germany: on a sunny summer weekend solar plants generate at full capacity, no matter whether they are in the south or the north. If this electricity cannot be exported or stored, market prices drop to zero (or below in case of flexibility shortage), and electricity will need to be spilled. Unsurprisingly, the dispatchable power plants need to adapt their operations and minimize their output during such periods of particularly sunny or windy weather.

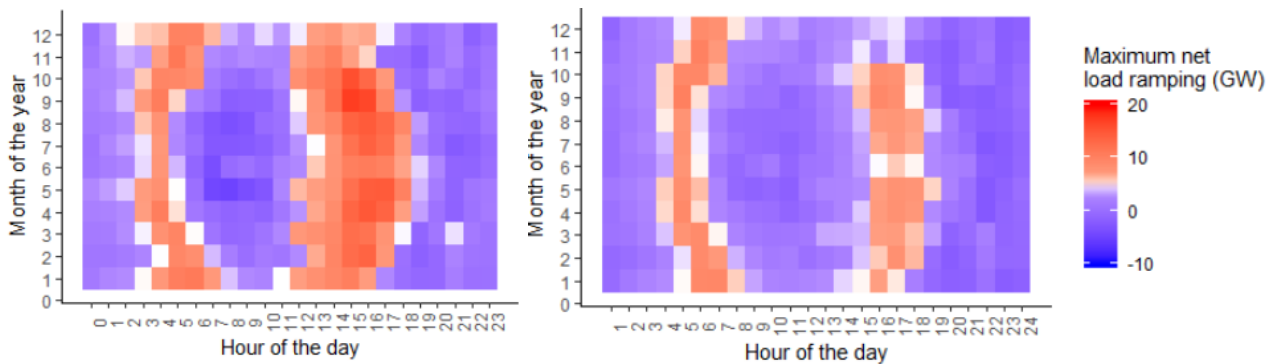
Figure 23. Effect of increasing shares of variable renewables (50%, 60% and 70%) on hourly ramps durations



Source : Own elaboration

As more renewables enter the power system, the net-load ramping – positive or negative – from one hour to another, becomes more pronounced (figure 23). For instance, with a share of renewables of 60%, the maximum net load change between two hours amounts to 17 GW, some 7 GW more than the empirically observed maximum ramp in 2018 (when the share of renewables was 37.8%). This means that the dispatchable power plants need to be able to adapt their output quickly from one hour to the next, ensuring the integration of variable renewables without risking a variation in frequency and the stability of the grid.

Figure 24. Hourly net load ramps across the year



a) 60% renewable scenario

b) 2018

Source : Own elaboration

Going into more detail and looking at the daily ramping pattern reveals that, despite an increase in the share of renewables to 60%, there remain two distinct positive ramping periods: one in the morning and one in the afternoon (figure 24). However, compared with 2018, the ramping episodes become longer and more pronounced as the share of renewables increases. This is mainly due to further expansion of solar PV in the German energy mix and implies that output from dispatchable power plants needs to mirror the daily generation pattern of solar power through cycling operations.

Table 5. Flexibility metrics in prospective scenarios

Share of renewables	AUR	%Change	AR	%Change	MCF	%Change
50%	1.20	-	5.4	-	89.2	-
60%	1.31	9%	5.8	8.4%	97.3	9%
70%	1.47	12%	6.0	3.8%	98.2	0.9%

Source : Own calculation

Those findings are reflected in the evolution of the flexibility metrics (table 5). All metrics rise with increasing shares of renewables. The rise in the mean cycling factor (MCF) suggests that the coal-fired fleet cycles more to accommodate the growing share of variable renewables. In a similar way, the average ramping metrics also increase, both in absolute (for the entire fleet) and relative terms (per installed coal unit). Expanding the share of variable renewables thus means that the system requires power plants to ramp up and down quickly and be available when there is little or no generation from wind and solar plants.

Under the assumed fuel and CO₂ prices most coal-fired plants are dispatched before gas-fired plants, if the system needs additional generation to meet demand. Nonetheless, the generation from gas power plants grows slightly, as CCGT are able to compete with older coal power plant, and benefit from their flexibility attributes. Figure 25 shows the evolution of generation for each scenario. The expansion of renewables, and the associated merit-order effect, displaces thermal generation. Coal plants run less as the share of renewables grows (see table 6). The average load factor of the fleet drops to just over 30% in the 50% renewables scenario (in comparison, the average load factor stood at 35% in 2018) and further to around 20% and 15% in the 60% and 70% renewables scenarios respectively.

Table 6. Evolution of coal shares on the energy mix

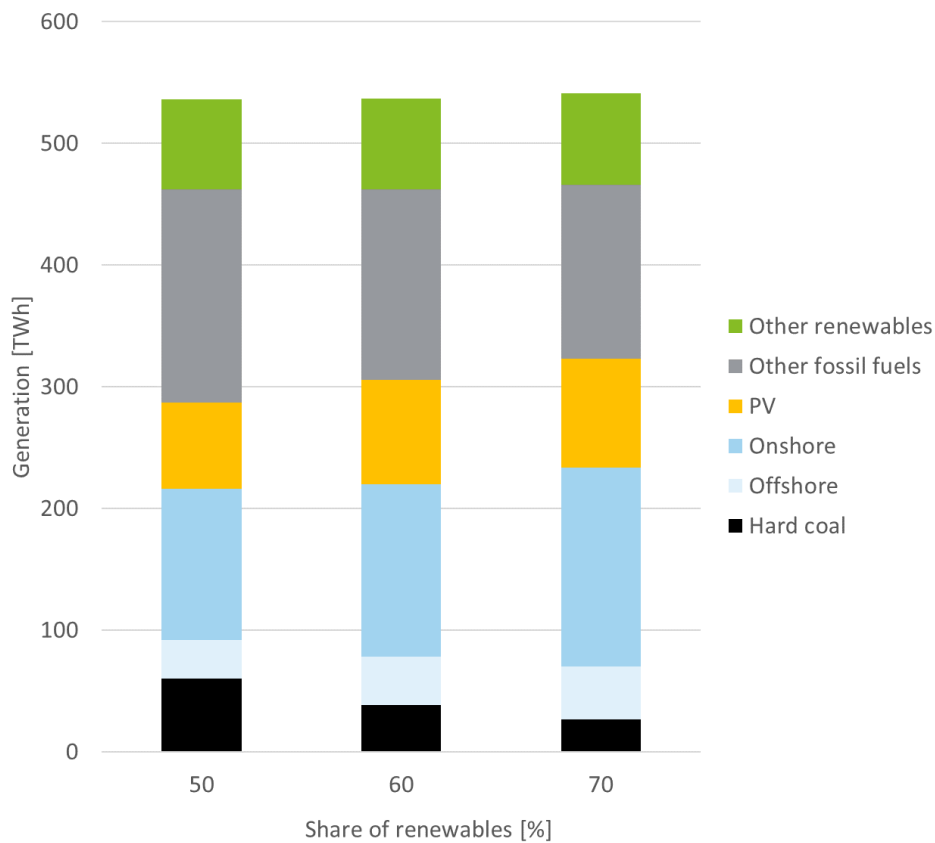
Historical		"What if" scenario				
Energy shares	Renewables	37.8% (2018)	Nuclear phase- out	50%	60%	70%
	Coal	13.2%		11.2%	7.2%	4.9%

The reduction in coal-fired output also results in a drop of the fleet's absolute ramps: coal is less required to meet the dwindling net load, and even if their ramps are steeper, they are less frequent as the fleet does not run in baseload anymore. Those two effects set each other off. As both values decrease in the same order of magnitude, the average ramping metric of individual coal-fired power plants (AUR) therefore stays relatively constant at around 0.9 (0) for shares of renewables below

50%. However, as the share of renewables increases to 60% and 70% the situation changes: the existing coal fleet ramps up and down less than before, but much more than compared to the decrease in power generation, which increases the indicator. It results in a steep increase of the Average Unit Ramping metric to nearly 1.4. Units cycle and ramp more than before; in other words, more ramps are needed per unit of electricity generated.

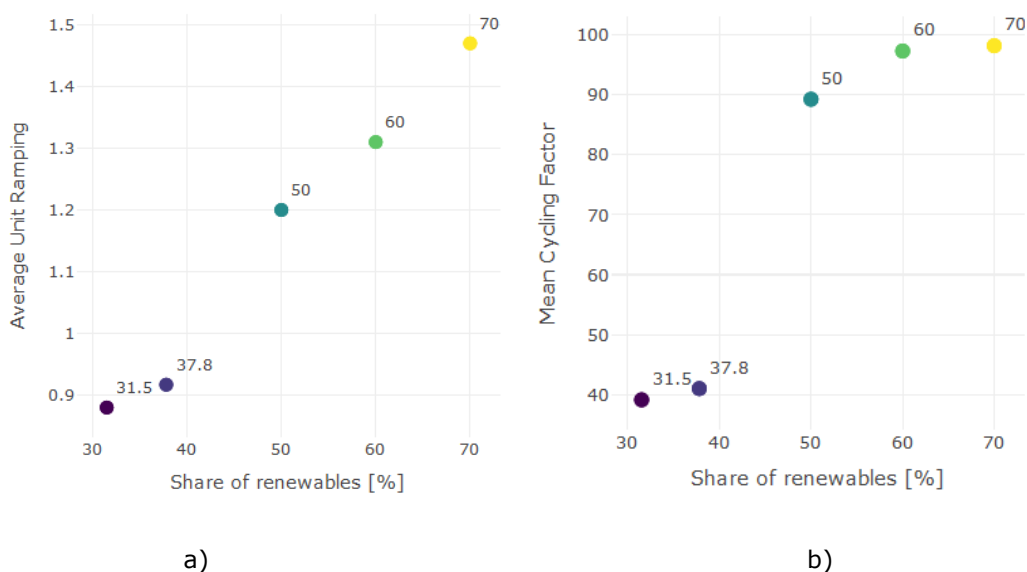
However, the coal fleet is not homogenous; neither in its age structure nor in its technical characteristics. The different plant types thus react differently to increasing shares of renewables. Unsurprisingly, modern and thus more flexible plants, adapt more easily to the changing market conditions. The latest designs achieve load factors far above the fleet average. In contrast, some of the oldest plants hardly run at all, being dispatched only in the tightest hours of the year. In our modelling framework such plants contribute to the system stability and adequacy but whether they could be profitably operated based on energy-only market revenues is questionable. This problem is not unique to old coal plants but also affects gas-fired power plants.

Figure 25. Evolution of the share of thermal and renewable generation between each scenario



Source : Own elaboration

Figure 26. Evolution of flexibility metrics with increasing share of renewables



Source : Own elaboration

3.3.3 A focus on mid-term flexibility

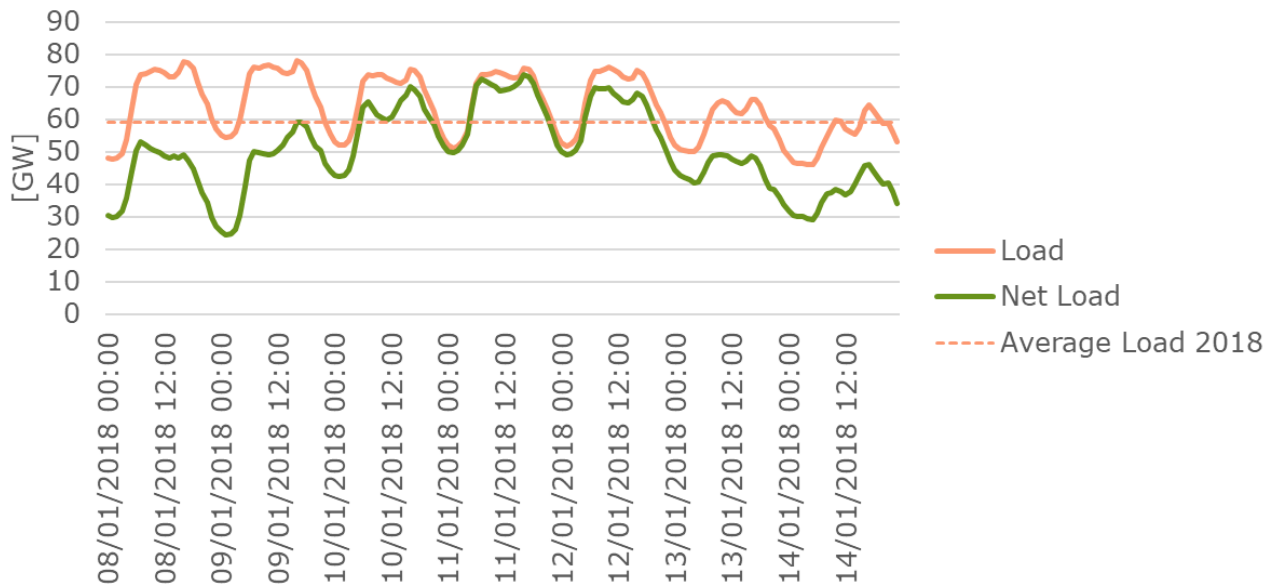
“Cold dark doldrums” are periods during which the infeed of renewable energies is very low and there is a significant demand of electricity to be met. Such periods may occur several times every year (see Appendix C) and might display different intensities and durations. The contribution of thermal power plants during such periods

is referred to as supply of mid-term flexibility. Coal-fired power plants in Germany have, to date, been critical in overcoming these extreme weather events, imposing an assessment of the role of coal during such events at higher shares of renewables.

For instance, the second week of January 2018 experienced a 72-hour period in which the infeed of variable renewable energies was relatively low while electricity demand was above the annual average (figure 27 and figure 28).⁵⁶

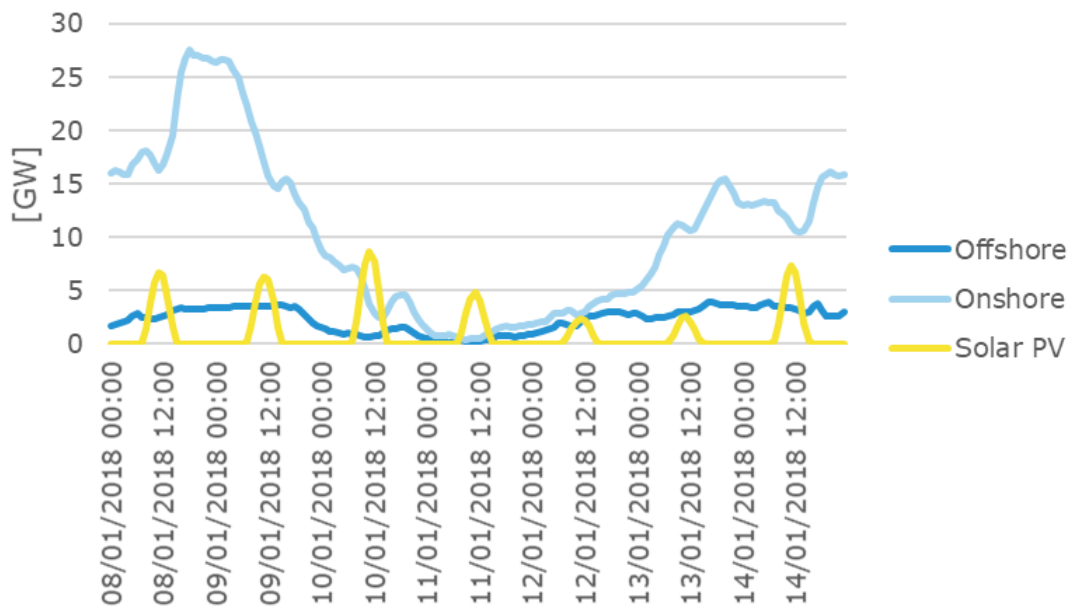
⁵⁶ The temperature during this week in January was relatively low in wide parts of Germany (e.g. less than 5°C on average in Hamburg, Berlin, München - <https://www.meteoblue.com>). Furthermore, all three days from January 10th to January 12th 2018 were working days, indicating that electricity demand was not reduced such as during weekends.

Figure 27. Load and net load curve for the second week of January 2018



Source : ENTSOE

Figure 28. Generation profiles of some renewables in the second week of 2018

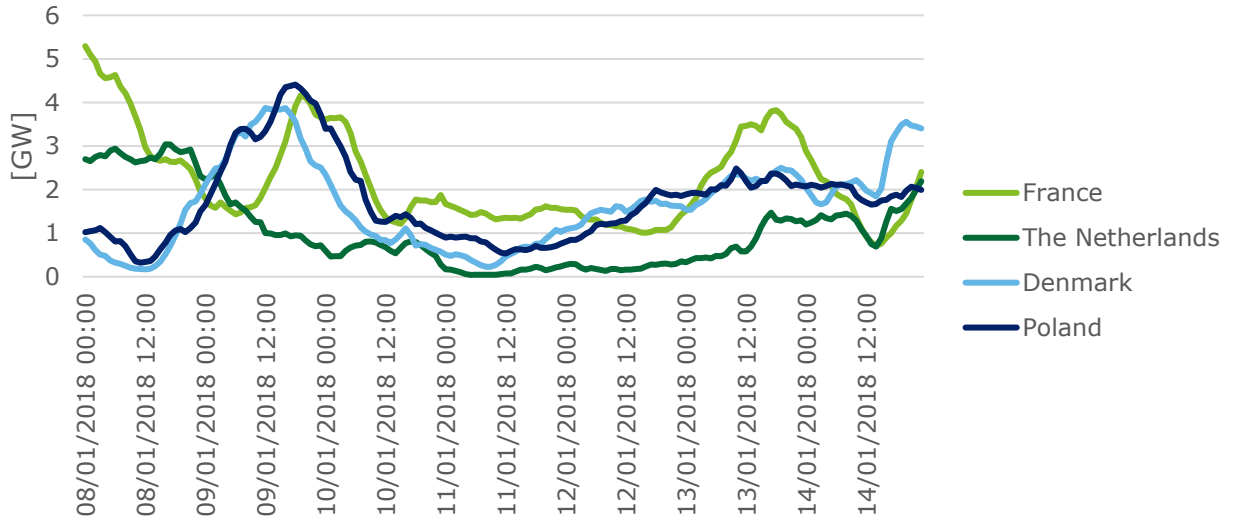


Source : ENTSOE

During those three days the average generation of electricity from solar PV, at its peak around noon, was around 5.2 GW, which is only 35% of the annual average at noon. At the same time, the generation from both onshore and offshore wind installations dropped to very low values. In the morning of January 11th wind production was only around 1 GW for several hours, which is less than 10% of the annual hourly average (12.4 GW). During this period Germany could not draw on importing surplus renewable energy from its neighbors as they were also experiencing low output from variable sources in those days 10th and January 12th (see Figure 29 for wind). As solar PV and

wind are weather-dependent, their availability can follow a similar pattern on a geographical scope wider than the country boundaries, spreading across surrounding balancing zones.

Figure 29. Wind generation in four key neighboring countries



Source : ENTSOE

Germany was a net exporter of electricity in 2018. During the three days period in January 2018 the drop in renewable infeed led also to a decrease in the cross-border exports to neighboring countries (Figure 30). While in the in days before and after the scarcity period the net exports were mostly above 6 GW, during the three days the exchange dropped to a mostly balanced level. In a few hours Germany even imported small amounts of electricity from its neighbors.

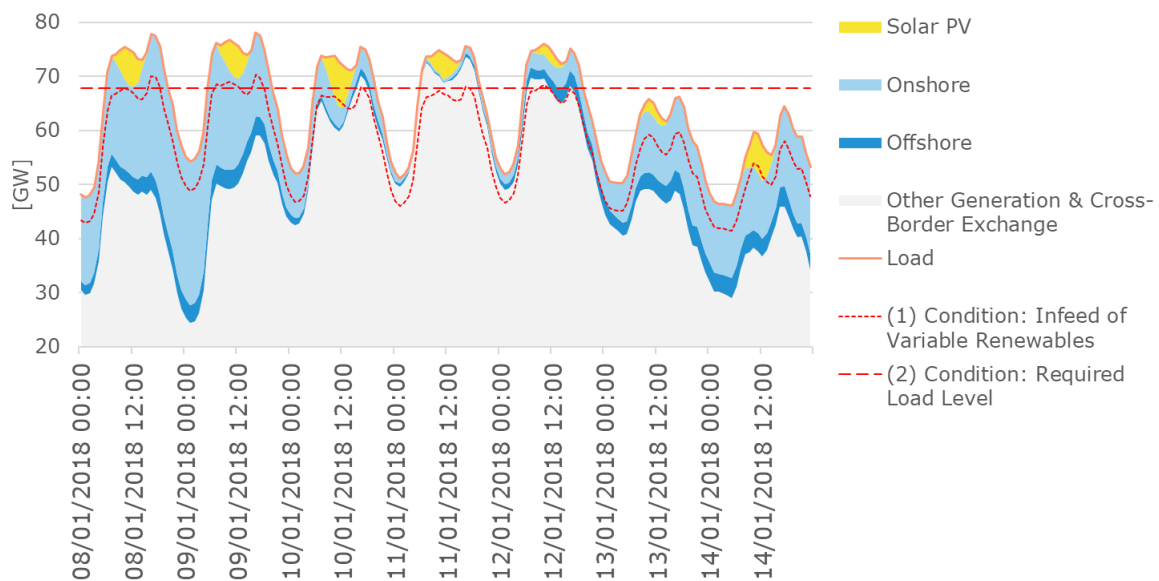
Figure 30. Net cross-border power exchange of Germany in the second week of 2018



Source : Own elaboration based-on ENTSOE

Power systems with high shares of renewables need to be capable of handling such shocks. Therefore, it is essential to understand the implications of unusual weather phenomena in terms of their intensity and duration. For this analysis two conditions are introduced for spotting such kind of low-probability high-impact periods: (1) the contribution of variable renewables to cover total load and (2) the requirement on the load level. Condition (1) is met when the contribution of variable renewables is less than 10% of the total load. Condition (2) is satisfied when the load level is above the threshold of 68 GW, which sets the lower boundary of the 25% highest load values within the considered year (figure 31 – red dotted lines).

Figure 31. Analysis of the 'Cold Dark Doldrum' episode in the second week of January 2018



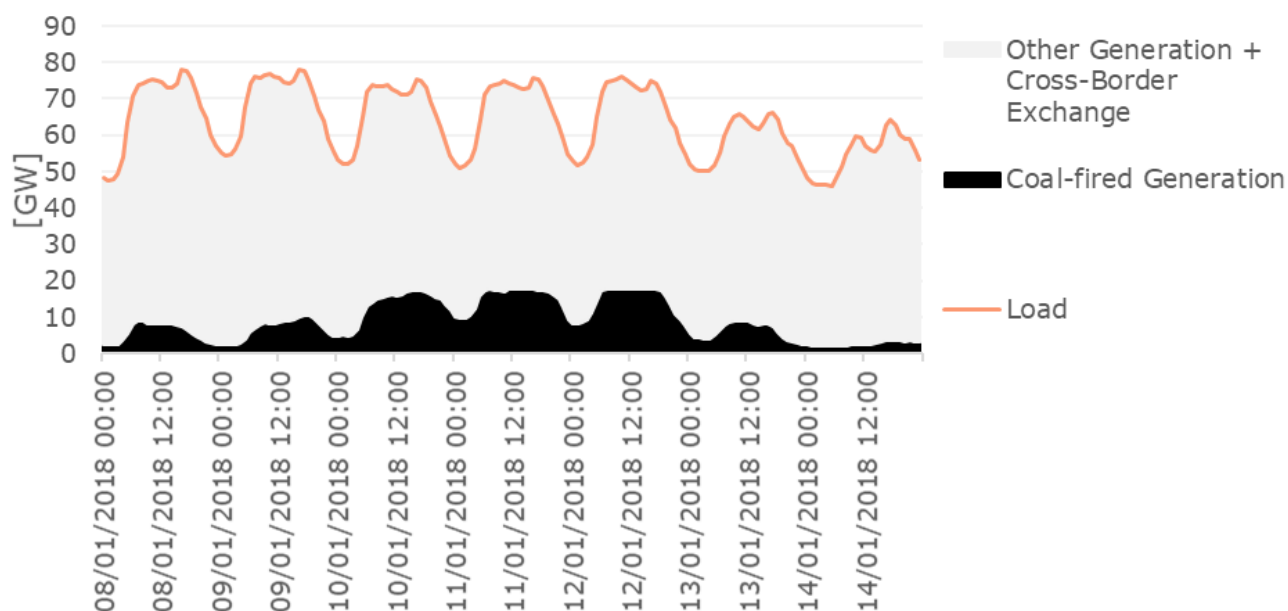
Source : Own elaboration based on ENTSOE

On January 11th 2018, during almost 60% of the days (i.e. 14 hours), both conditions were satisfied. Only during night hours, the load dropped below the defined threshold (condition (2)). During the entire day the infeed of variable renewables were always less than 10% of the load. Days during which 14 or more hours meet the two conditions, such as on January 11th, occur about seven times per year (See Appendix C). In the case of the second week of January 2018 there was even a longer period when a significant number of hours satisfied the conditions. By extending the period of analysis from January 10th to January 12th we found that in over 40% of the time (i.e. for 30 hours) both conditions were still met. In this period the generation of variable renewables exceeded the threshold of 10% of the load only during a few hours around noon on January 10th and January 12th. Episodes of such an intensity and duration occur with a frequency of about three times per year. The longer the duration of the cold dark doldrums, the less frequent it is but the more severe are its consequences. However, even periods with a duration of one week might still have a significant number of hours where the two conditions are satisfied. Every second year there is a week when, during more than 40% of the time, both conditions are satisfied (Appendix C).

During episodes of cold dark doldrums, dispatchable units are key to ensure an adequate balance between demand and supply. In January 2018 coal-fired plants significantly contributed to fill this gap in Germany. On average, coal has a share of 12% in the German power mix but during these three days the share of coal soared to over 20%. In a few hours the contribution of coal was over 17 GW which is more than double its average value (8 GW) (figure 32). Nearly 5 GW of installed coal-fired generation were unavailable so that the remaining fleet was close to its maximum power

output around noon on January 12th. Furthermore, the coal-fleet significantly contributed to ramping needs. In the evening of the same day the fleet ramped down by over 13 GW in 8 hours.

Figure 32. Dispatch of coal-fired power plants in the second week of January 2018



Source : Own elaboration based on ENTSOE

In scenarios with high shares of renewable energies the implications of such periods intensify. During a short cold dark doldrums period (i.e. one to three days) the average generation of coal-fired power plants is at least 2.4 times higher than on yearly average (table 7), and this ratio increases with higher shares of variable renewables. In a system composed of 70% renewables, the call on coal-fired power plants during a 3-day cold dark doldrums period is nearly four times higher than on a normal day.

Overall, when analyzing the conditions for identifying a potential 'cold dark doldrums' episode over longer durations (four to seven consecutive days), such periods use to include some punctual moments where such conditions are not met continuously (e.g. they include weekends and some short sudden upsurge of wind and/or solar power), but still the proportion of hours at which they are met might be relevant for energy security concerns (i.e. we could find a 3-day cold dark doldrums, interrupted by a slight decrease in demand during the weekend and followed by another 1-3 days period where conditions (1) and (2) are met again on the immediately following days)⁵⁷. This explains why the call on coal-fired power plants might decline when considering longer time windows of analysis (e.g. 7 days instead of 3 or 1 day).

Thermal generation capacities, including coal-fired power plants, play an insurance role for the power system for managing such low-probability but high-impact weather-related events. The capability of managing such events is what is referred to in this study as the supply of "mid-term" flexibility, which is related to capacity adequacy and risk management considerations. These results show the extent to which coal-fired power plants contribute to the provision of "mid-term" flexibility which becomes more important as the share of wind and solar increases.

⁵⁷ When studying a time window of seven consecutive days, we find that the contribution of coal goes from 1.5 to 2.1 times higher than the yearly average for 50% to 70% variable renewable shares respectively, which are still relevant figures even if the entire week does not entirely satisfy conditions (1) and (2).

Table 7. Ratio of coal-fired power generation during a 'cold dark doldrums' episode over average coal-fired generation

		Share of renewables in the German power system		
		50%	60%	70%
Duration of the considered dark cold doldrum	1 day	2.6	3.6	4.8
	3 days	2.4	3.1	3.8

Source : Own elaboration

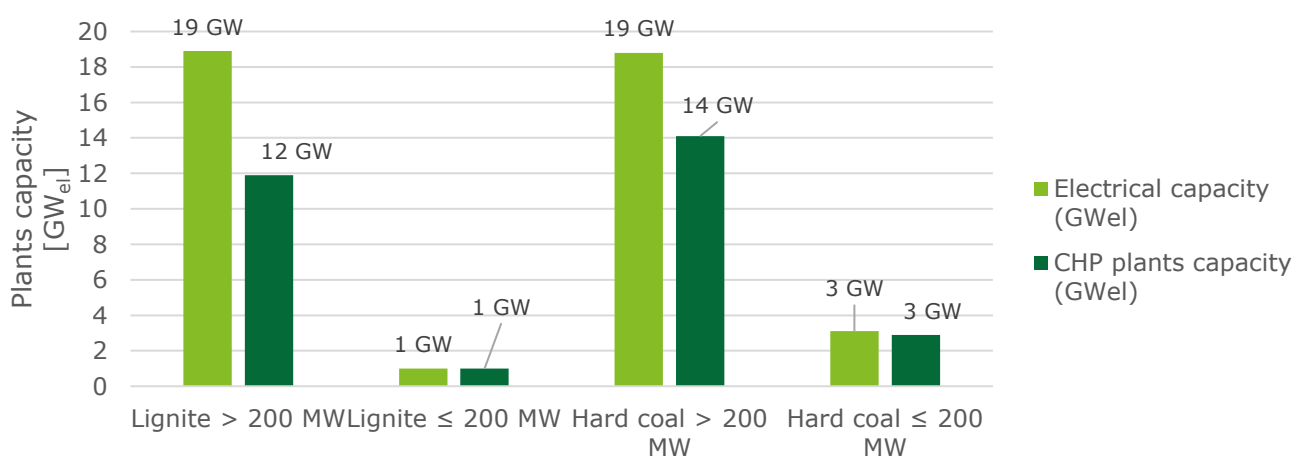
3.3.4 A focus on thermal storage retrofits

As explained in section 2.2 there are numerous ways of improving the flexibility of coal-fired power-plants. The effect of such improvements is to enlarge the operational range of the plant and/or to enhance efficiency. Since higher shares of variable renewables cause more variations in the power system, a larger operational range enables them to better adapt to changing system needs. For this study we focus on thermal storage retrofits. Behind this term there are however two different options for improving the performance of coal-fired power plants. The first one refers to the capability for CHP power plants to decouple the production of heat and electricity, therefore improving their flexibility (that are sometimes considered as must-run units). The second one refers to the usage of water pre-heating systems to allow running the boiler in a smoother way, so enhancing the fuel efficiency, the flexibility attributes and the emission factor of the plant.

Thermal storage for CHP power plant

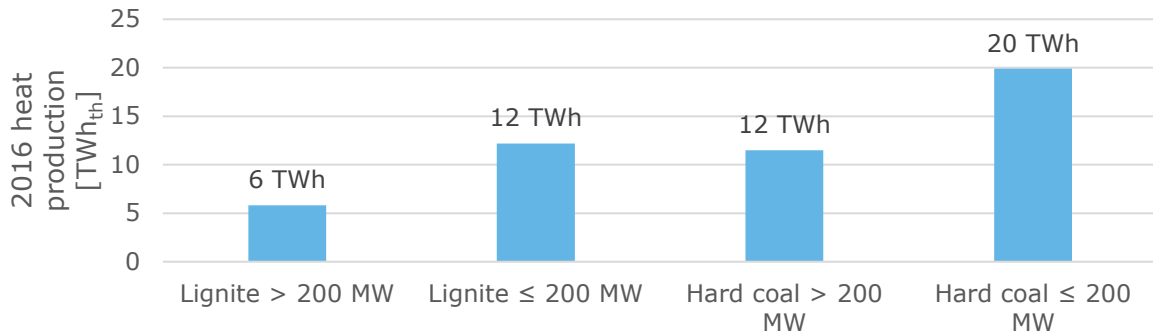
CHP power plants are the bulk of coal installed capacity in Germany (17 GW out of 24 GW of installed coal power plant provide heat) (Mersmann et al., 2019). However, most of the heat produced comes from small power plants, whose primary product is heat from co-generation meeting the need of residential districts and industries. On the contrary, larger units serve mainly electricity demand and therefore sell heat only as a by-product (figure 33). Consequently, 13% of total coal power plant capacity (small CHP units) are responsible for 63% of the total heat production from coal.

Figure 33. Installed capacity of coal and lignite fired power plant by size



Source : (Mersmann et al., 2019)

Figure 34. 2016 heat production of coal and lignite fired power plant by size

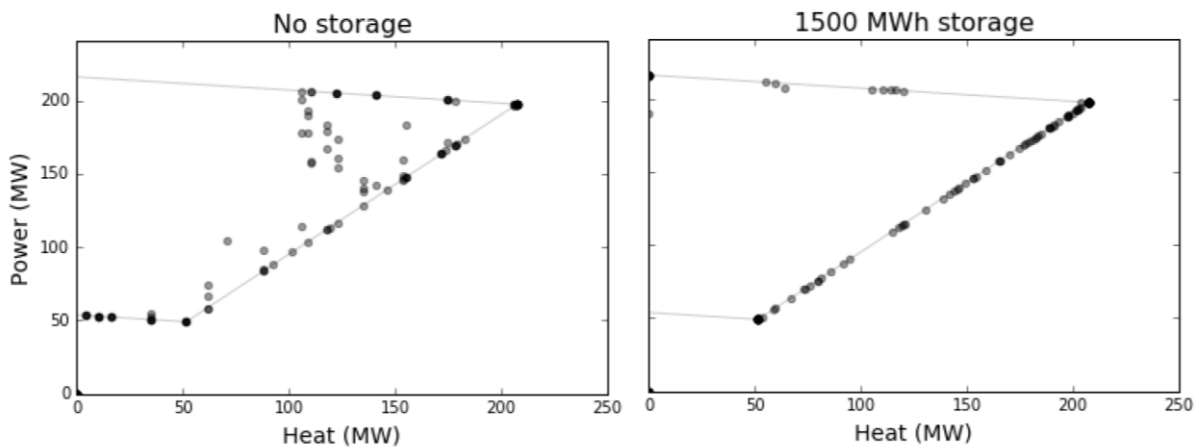


Source : (Mersmann et al., 2019)

As those units serve both heat and electricity demand, their dispatch is less flexible, in theory. They must produce heat even in periods when electricity is not needed because of the strong inelasticity of heat demand. That is why they are commonly considered as ‘must-run’ capacity on the electricity market: they are often ran regardless the electricity prices. However, by adding a heat storage capability to the plant (or to the district heating network they feed in) it is possible to continue supplying heat with just very little or no electricity supply.

Decoupling heat and electricity allow indeed for the power plant to produce electricity at times when it is most valuable and stop producing when it is not, while the heat demand continues to be supplied by the storage unit. Stored heat will then be released when needed (and potentially without producing electricity if market prices are too low). The advantage of such heat storage is also to let the power plant operate only at the most efficient load point (figure 35) inducing better fuel efficiencies and driving down CO₂ emissions.

Figure 35. Hourly CHP operation points for a week in winter (extraction turbine).



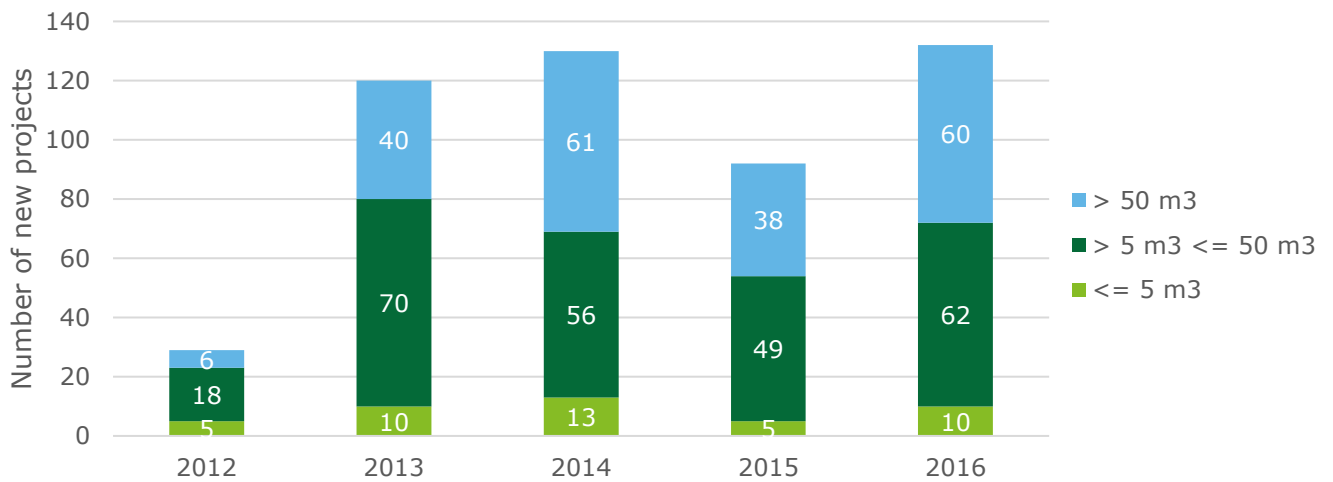
Source : (Navarro, 2017)

The most common way to accommodate such storage is by adding water-storage tanks. Various different designs have been tested (de Wit, 2007), including vertical or horizontal insulated steel tanks, multiple-tank systems, underground versions, all of this being related to the size of the associated plant. If the exact return on investments really depends on the local prices and contracts

for heat, the investment price for such heat storage is negligible compared to the cost of a cogeneration plant according to de Wit (2007).

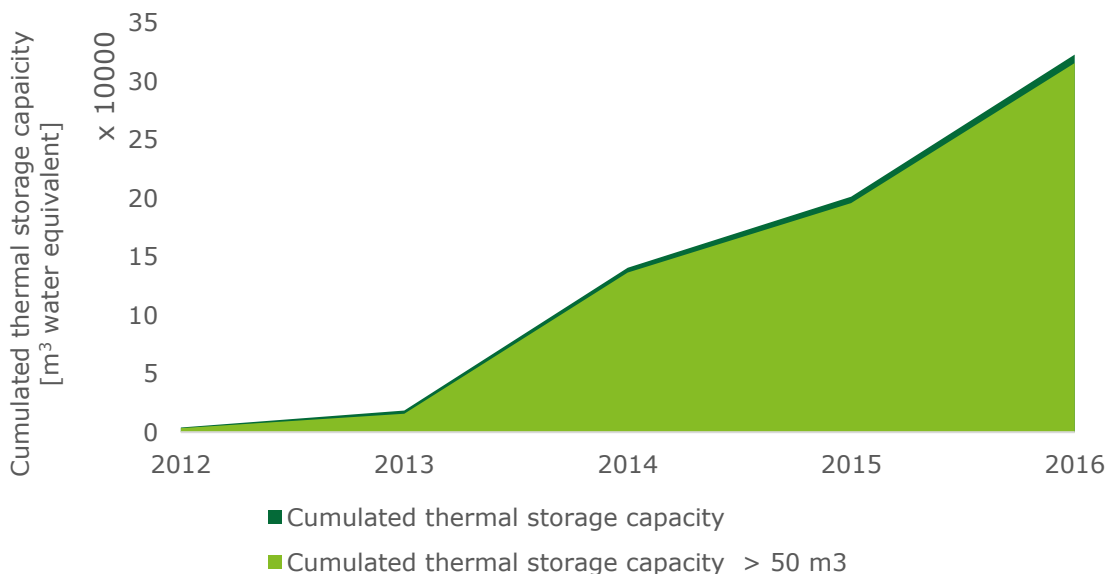
The Kraft-Wärme-Kopplungsgesetz has been enforced in Germany since 2002 and supports the development of CHP power plants as they attain higher overall efficiencies by taking advantage of the heat that is produced when generating electricity. With the amendment made in January 1, 2016, the legislation has doubled the volume of support, with the aim of improving flexibility and lowering CO₂ emissions. This has resulted in a growing amount of projects of thermal storage and installed capacity (figure 36 and figure 37), most of them being of large unit size.

Figure 36. New thermal storage project under the KWKG by size of thermal storage retrofit



Source : (BAFA, 2019)

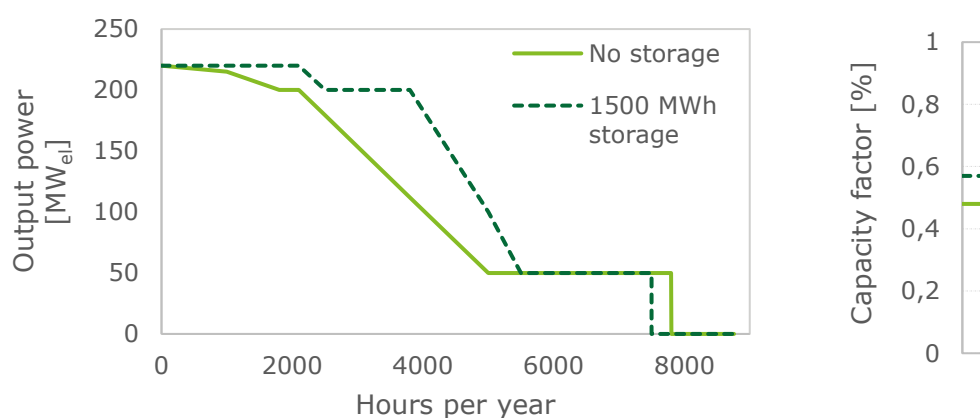
Figure 37. Cumulative added thermal storage retrofitted capacity under the KWKG



Source : (BAFA, 2019)

Adding storage capabilities does not improve the flexibility parameters of the plant itself but brings a major advantage in terms of enhancing market arbitration opportunities and overall operating range between the heat and the power delivery (figure 38). According to Navarro (2017), higher amounts of renewables could be integrated in the system via a more flexible operation of CHP units. Indeed, the more flexible their heat/power output is, the better they could accommodate the variability of wind and solar operating in load following in the electricity market mode instead as “must run” capacity. “Today, practically all CHP plants in Denmark, both small and large, have heat storages” (CEM, 2018, p. 11).

Figure 38. Load duration curve of a CHP plant and capacity factor for scenarios with and without thermal storage retrofits



Source : Based on (Navarro, 2017)

Feed water pre-heating through thermal storage system

The technical flexibility attributes of coal power plants can as well be improved through the addition of thermal storage as an additional source of heat to counterpart the boiler. Those attributes are, as discussed in Section 2.2, the minimum load, the ramping rates, and minimum up/down time. The core idea of the thermal energy storage retrofit discussed here lies in the addition of a system buffering heat from the boiler (i.e., within the facility of the plant) to maintain its operations as stable as possible and to attain lower minimum electricity outputs than required, so avoiding combustion stability issues, thermal and mechanical stress, and extra fuel consumption during persistent start-ups and shut downs of the plant.

Reducing the minimum load of the plants is paramount when dealing with increasing shares of variable renewables as start-ups are energy and CO₂ intensive. At the system level, the ability to stay online with very little output, rather than shutting down, also benefits grid stability and therefore allows accommodating higher amounts of variability (Agora Energiewende, 2017). But the minimum output of the boiler is constrained by combustion stability issues, and its components are very sensitive to thermal stress (including seals degradation, tube rubbing, boiler hot spots, drum humping/bowing, among other wear and tear). It is a standard practice for steam turbines to pre-heat the feed water before feeding the boiler to enhance its efficiency and prevent failures. Water pre-heating is usually implemented by recovering heat from flue gases which requires the continuous operations of the boiler and the turbine. By adding additional thermal storage capacity looping the boiler it can be driven at similar minimum stable levels but feeding not only the turbine but the storage system as well (i.e. when charging the thermal storage system), thus, the resulting infeed

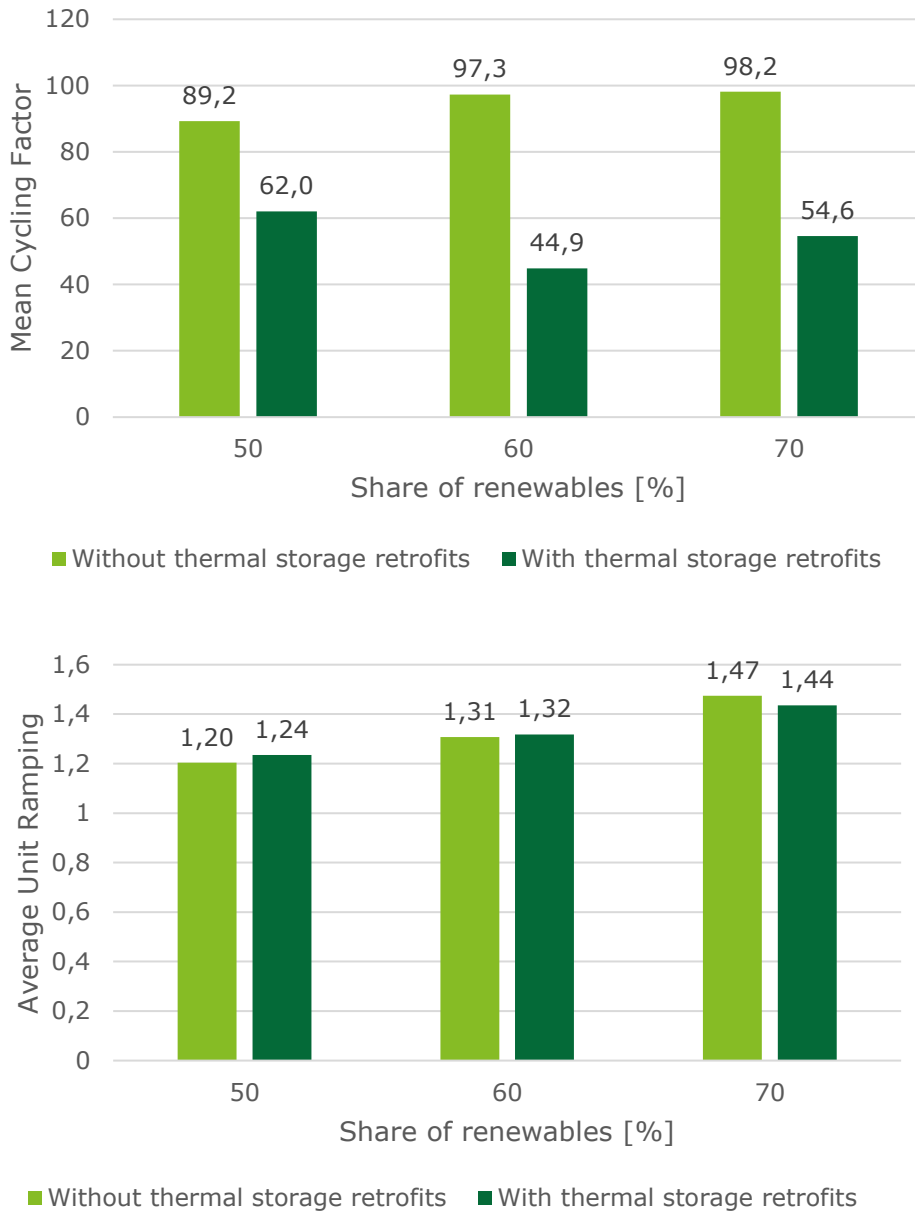
of the turbine would be reduced leading to an overall decrease of the minimum power supply of the plant. Moreover, when the thermal storage is discharging, the turbine can be slightly overloaded for some period if there is a need for additional capacity. Typical values reported in the literature highlight a decrease in minimum power between 5 to 10-percentage points with this kind of retrofit (Agora Energiewende, 2017, p. 67)⁵⁸. Excess heat that is fed into the storage system, during times when it is not needed or valuable, is energy putted on hold that can be used instead of fuel the next time the unit needs to increase its load (i.e. discharge mode), leading to a reduction of fuel consumption and CO₂ emissions.

The state-of-the-art thermal storage options that are currently being considered include molten salt storage, Ruths-storage and solid heat storage systems (Loeper et al., 2019). In solid heat storage systems a gaseous stream is injected into the storage system. By rushing around solid materials such as metals or natural rocks, heat is directly transferred to the material. Ruth-storage systems are pressure reservoirs partially filled with water. During the injection process, hot thermal streams condense in the storage system. The pressure, the temperature and the water level in the storage system increase. During the discharging process, the saturated steam is released from the tank. Molten salt storage systems usually operate with two tanks (high and low temperature). Thermal energy is injected and released from the molten salt storage between the high and the low temperature tank using heat exchangers.

To illustrate the benefits of adding thermal storage for feed water pre-heating, the three prospective scenarios have been re-assessed assuming that the entire coal-fired power plant fleet, both CHP and electricity-oriented plants, have implemented such thermal storage retrofits, thus allowing them to attain 10 percentage-point decrease of their minimum stable load and a 12 hours of autonomy for supplying heat without any power generation for CHP plants. Such an ideal case corresponds to an upper bound of the flexibility enhancements of existing units due to thermal storage retrofits (see figure 39). However, as any other retrofit, adding thermal storage implies additional investments that needs to be justified by enhanced market revenues (e.g. improved cost arbitration opportunities on the market) and/or avoiding operating costs (e.g. reducing maintenance and failures of components, reducing fuel consumption and CO₂ costs). The profitability of implementing such retrofits is unit dependent and requires a regulatory framework that provides enough visibility to incite investors.

⁵⁸ "It is important to note that the reduction of net power has no influence on the firing rate in the boiler." (Agora Energiewende 2017). Agora Energiewende also reports that according to Schmidt and Schuele (2013) an increase of ramping abilities for up to 30 min can be attained with small heat water tanks.

Figure 39. Flexibility metrics with and without thermal storage retrofits



Source : Own elaboration

The Mean Cycling Factor obtained with thermal storage retrofits is 30%, 54% and 44% lower than without storage on the three renewable energy penetration levels considered. This is in line with the awareness that thermal storage allows lower minimum stable power, thus, the plants would then need to change commitment less often due to the enlarged operational zone obtained after the retrofits. However, the increasing trend of the Mean Cycling Factor with increasing renewable energy shares one case without storage is somehow flattened when upper bound storage is assumed, which depicts the idea that such retrofits allows almost completely de-couple the number of cycles the plants suffers to integrate variability from wind and solar. The impact of thermal storage on the Average Unit Ramping metric is mitigated but keeps a similar ascending trend. This is explained by the fact that given that thermal storage provides just a marginally broader operational range, the ramps can only be marginally deeper with increasing variability from wind and solar.

3.4 Discussion of results

Our historical analysis confirms the IEA's assessment that Germany is currently in phase 3 of variable renewable energy integration. This means the existing power plant fleet adapts its operations to provide the necessary flexibility for growing shares of wind and solar power in the German power system. The model runs, carried out with DEEM, demonstrate that in the years 2015 and 2018 (similar results can be expected for 2016 and 2017) coal-fired power plants have been instrumental in integrating fluctuating output from variable sources into the grid.

The shares of wind and solar power can be expected to continue growing. Not only are the decreasing costs for these technologies tilting the economic calculation in their favor, but the German government (alongside other European nations) has set itself ambitious targets to further expand deployment of renewable energies. We have studied whether renewable energy shares of 50%, 60% or 70% (as compared to the 37.8 % reached in 2018) would alter the way coal plants in Germany are operated and whether their technical characteristics are compatible with a further increase in wind and solar power.

Detailed model runs suggest that the existing dispatchable fleet in Germany, including the installed coal plants, pose, from the point of view of flexibility, no barrier to further expansion of variable renewables. The flexibility metrics developed in this study indicate that coal plants ramp more often and cycle more intensely as the share of variable renewables increases. (Technically speaking, the plants change their operational status – offline, online, and go from minimum load to full load and back again – more often).

The output from coal-fired power plants drops as the share of renewables increases but remains, with 45 TWh or 8.2% in a 70%-renewables scenario (compared to 72.3 TWh or 13% in 2018)⁵⁹. The decline in coal-fired output is largely attributable to additional renewables displacing thermal generation, rather than a fuel-switch from coal to gas. The average load factor of the fleet drops to just over 30% in the 50% renewables scenario (in comparison, the average load factor stood at 35% in 2018) and further to around 20% and 15% in the 60% and 70% renewables scenarios respectively.

However, the coal fleet is not homogenous; neither in its age structure nor in its technical characteristics. The different plant types thus react differently to increasing shares of renewables. Unsurprisingly, modern and thus more flexible plants, adapt more easily to the changing market conditions. The latest designs achieve load factors far above the fleet average. In contrast, some of the oldest plants hardly run at all, being dispatched only in the tightest hours of the year. In our modelling framework such plants contribute to the system stability and adequacy but whether they could be profitably operated based on energy-only market revenues is questionable. This problem is not unique to old coal plants but also affects gas-fired power plants. It forms the heart of a debate around what market designs can safeguard the integration of variable renewables without jeopardizing the economic viability of the dispatchable fleet.

The fact that a large portion (nearly three quarters of the installed capacity⁶⁰) of the German coal plants produces heat and electricity at the same time, is both a challenge and an opportunity for flexibility provision. Co-generation allows for switching between heat and electricity flexibly and seamlessly (i.e. minimizing losses during times of high renewables infeed) but may also constrain the availability of electricity output during cold weather periods. In either case, thermal storage retrofits can improve the operational flexibility of coal plants.

⁵⁹ It should also be noticed that the 70%-renewable energy scenario also assumes a total nuclear phase-out. Thus, the development of renewables not only take the current shares of nuclear but also some's of coal.

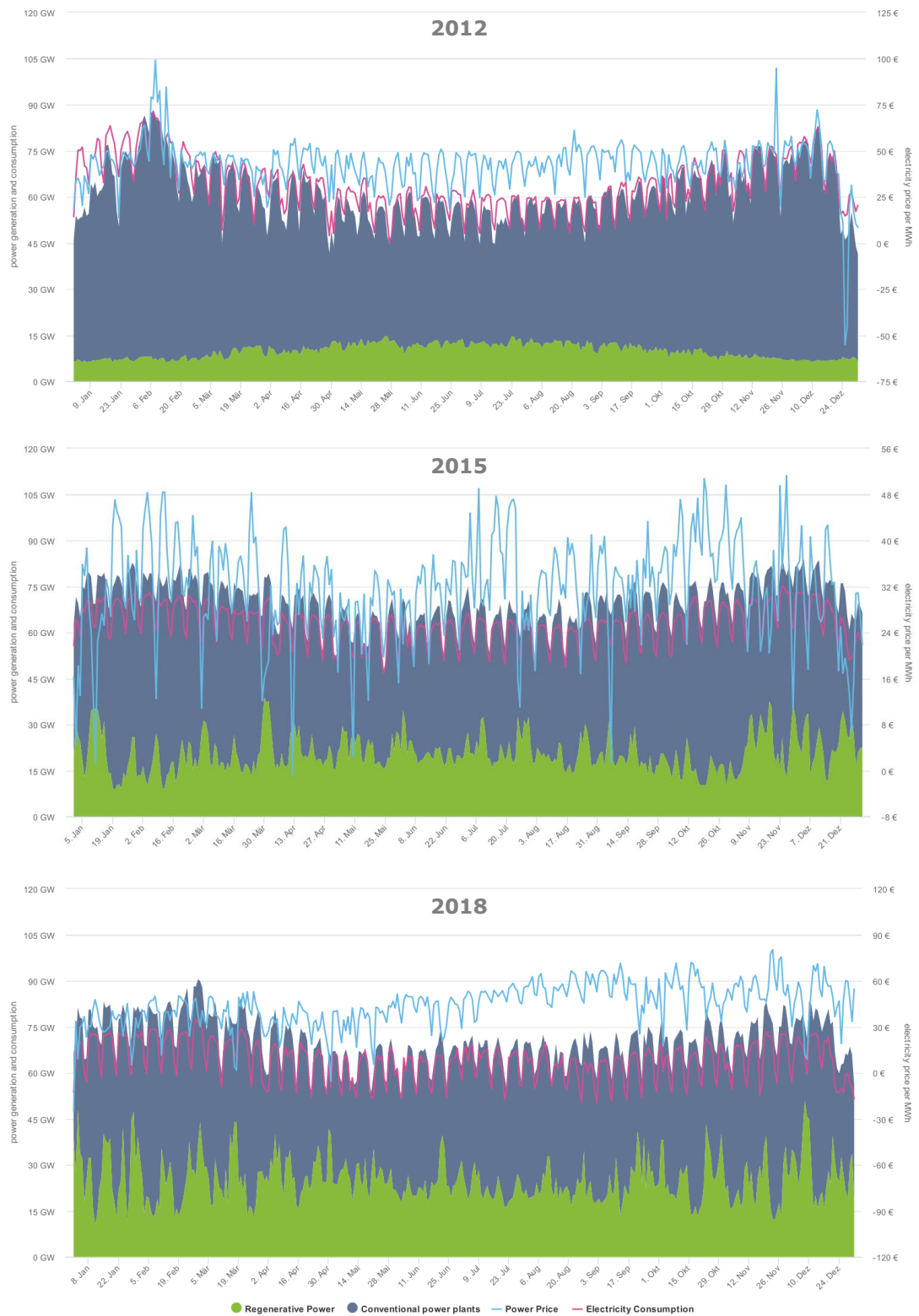
⁶⁰ This is 14 GW out of 19 GW of coal-only capacity in Germany also supplies heat (73%), but this figure goes up to 89% when considering coal plants with mixed secondary fuels (3 GW out of 3.3 GW). Further information available at: [Kraftwerksliste der Bundesnetzagentur](#)

In light of the future power generation mix being, not only in Germany, increasingly determined by policy decisions (nuclear phase-outs, coal phase-outs, renewable expansion targets, etc.) rather than economics, the model runs are not based on a least-cost expansion of the fleet. Neither have we attempted to 'best-guess' the future mix, avoiding any notion of forecasting or opinion. Instead, we adopted a "what if" scenario approach to isolate all of those external factors from our study. This comes at the cost of potentially underestimating the role of emerging battery storage technologies, demand response and electric vehicles on the provision of flexibility on mid-term scenarios. Whether these would, in our analytical framework, reduce the scope of coal or gas plants to provide flexibility is however unclear without a dedicated model run.

The assumed fuel and CO₂ prices (despite the assumed increase in CO₂ prices) reflect the economics between coal and gas plants broadly observed over the years 2015 to 2018, i.e. a price constellation that places the bulk of the coal-fired fleet before gas-fired plants in the merit-order. Coal-fired plants are thus – as long as their technical characteristics permit – dispatched before gas-fired plants, if the system needs additional generation to meet demand. A higher CO₂ price trajectory than the one assumed here, could thus lead to a 'fuel switch' and place gas before coal in the merit-order, and thus the gas-fired fleet would provide higher energy shares and more flexibility.

Appendix A

Figure 40. Evolution of electricity dispatch in Germany and electricity prices.



Source : Agora Energiewende 2019

Appendix B

Main hypothesis made for the modeling.

The Deloitte European Electricity model (DEEM) is a mixed-integer optimization model. It is adjusted for the needs of the study to be able to assess the flexibility both on an historical point of view and for a prospective one. Main hypotheses are listed below.

For the historical perspective we used data from ENTSO-E Transparency Platform. It allows us to reproduce previous dispatch to assess the flexibility of the existing coal power plants. For the prospective study and to capture only the effect of an increasing share of renewables, everything has been kept as-is except for the CO₂ price and the installed capacity of renewables in Germany. As such, we can consider only the effect of the renewables and not any noises linked to an increasing interconnection capacity or changes in the production mix.

A unit commitment is performed, accounting for technical capabilities of thermal power plants. Maximum and minimum load ramping is taken into account, as well as minimum and maximum power output, start-up costs, and number of units in operation.

CHP has been modeled in a simplified way for Germany for the prospective study. Two types of technologies have been considered: back-pressure turbine and extraction turbine. Data comes from both (Danish energy Agency 2016; DIW 2017) for Power-To-Heat factor, CHP technology and installed capacity. Generic values have been used for missing data, both Power-to-heat factor and Loss ratio. Additional way of providing heat at the country level has been made possible through electrical boiler to avoid any infeasibilities.

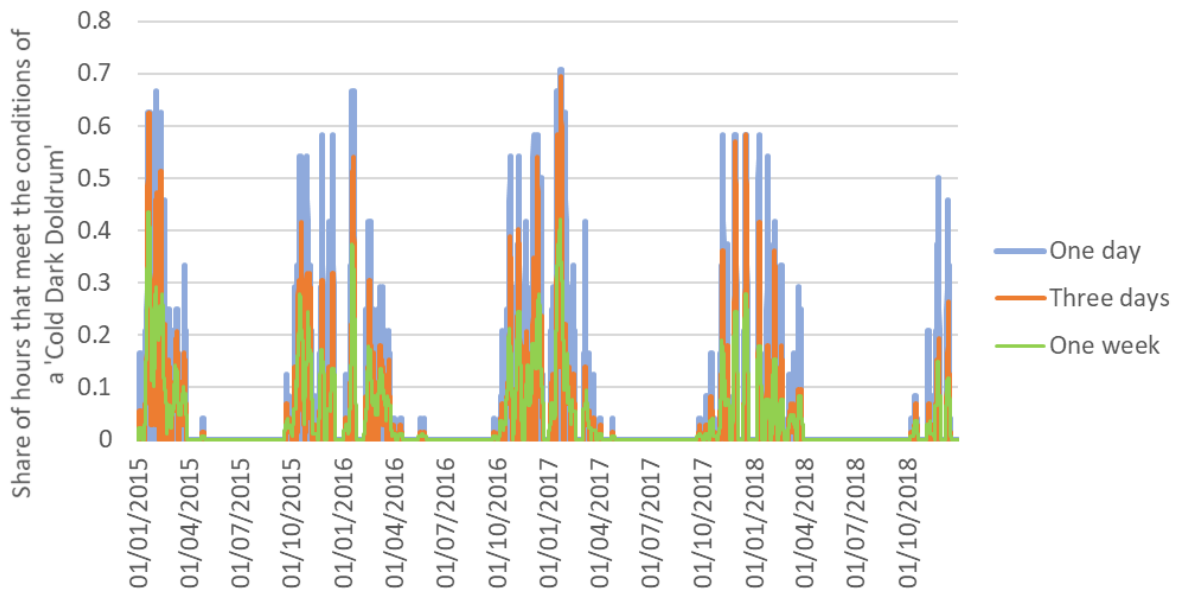
Appendix C

Cold dark doldrum are periods with relatively high electrical demand and little electricity generation from intermittent renewable energies

Following the definition of a 'cold dark doldrum' given in section A focus on mid-term flexibility 3.3.3, there are two conditions that need to be satisfied: (1) a low infeed of variable renewables and (2) a relatively high electrical load compared to the annual average. In this analysis hours are considered to meet those conditions when there is less than 10% of the electrical load covered by variables renewables (1) and when the electrical load of the considered hours is in 25% of the highest values of the considered year (2).

In the period between 2015 and 2018 each individual hour is analyzed based on the two conditions using a rolling horizon approach (Figure 41). This means that for a cold dark doldrum analysis of one day the eleven hours before and the twelve hours after the considered hour are taken into account. Consequently, for a duration of three days the 35 hours before and the 36 hours after and for a length of a whole week the 83 hours before and the 84 hours after are considered. The share represented on the vertical axis in Figure 41 illustrates the ratio of hours that satisfy both conditions to the number of hours considered (e.g. 24 hours for one day, 72 hours for three days and 168 hours for one week). The higher the value, the more hours satisfy both conditions. To give an example: If the share of an hour is 0.75 for a one day duration, it means that 18 hours out of 24 hours around this considered hour met both conditions.

Figure 41. Analysis of coal dark doldrums in Germany between 2015 and 2018



Source : Own elaboration

Periods where both conditions are satisfied mainly occur during winter months. The length and the intensity of such periods vary substantially. While there are many single days with high relatively

high values (e.g. above 0.4), there are less periods of longer periods (e.g. three days or one week) that reach comparable amplitudes. With an increasing considered duration, the share of hours that satisfy both conditions decreases. Single days with a share of more than 0.4 occur about 14 times per year. Three days periods with the same share occur 3 times per year. Between 2015 and 2018 there were even two periods (in January 2015 and 2017) where 40% of the hours in one week, corresponding to more than 68 hours, both conditions were satisfied. Section 3.3.3 describes the importance of electricity generation by coal fired-power plants for such a period in the past and their role in scenarios with increasing shares of renewable energies.

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