FLEXIBILITY NEEDS AND OPTIONS FOR EUROPE'S FUTURE ELECTRICITY SYSTEM

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Compiled for EUGINE – the European Engine Power Plants Association

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EXECUTIVE SUMMARY

From the ongoing decarbonisation of the energy sector the need for flexibility in electricity markets is emerging. Decentralized and fluctuating solar and wind feed-in is substituting more and more power from central, steerable and often fossil-fired power plants.

Supplying flexibility will become a key role for all actors in energy-related sectors: steerable power plants, demand, energy storages, heating and mobility applications need to provide different types of flexibility: Short-term electricity balancing, congestions management and imbalance management needs to be done in a regime with fluctuating and unknown supply and demand. Forecast-deviations are high when the dispatch is planned day-ahead, the deviation of forecasted wind feed-in is about 5 percent of the installed onshore capacity on average. Oversupply with low residual loads will occur as well as high residual loads. Thus medium-term flexibility is needed as well. Even seasonal balancing will become more and more important with very high shares of variable renewable energies: When averaging 31 days the generated load could fluctuate between 4 percent of the installed capacities using the weather-data of summer 1994 and 61 percent using the weather-data of winter 2006/2007.

The different flexibility sources are as different as these flexibility needs. Start-stop cycles, reaction time, low fixed and variable cost, start-up capability and operation range have been identified as crucial parameters. There is no flexibility option offering all these flexibility needs efficiently, it is a mix of different options which performs best. Batteries are suitable to provide frequency control energy, as they have the quickest reaction time. The potential of demand-side management increasing load is bigger than decreasing load, where consumer habits strongly restrict particularly long-lasting load reductions. Only when taking into account heat and mobility applications, demand side management will play a major role in providing medium term flexibility as well. E-mobility could balance out residual load fluctuation up to a daily basis and power-to-heat in combination with heat storages could reduce short-term temperature-dependencies in the electricity sector. Pumped hydro power plants are a mature and cost-efficient flexibility option for short and medium-term applications, but their capacity is limited by geological and geographical conditions. Power-to-gas/-liquids as an electricity consumer provides downward short-term and medium-term flexibility on one hand. Its products on the other hand are storable on a seasonally basis and in combination with the gas infrastructure and gas-fired power plants are therefore the only upward flexibility option from short- to long-term.

Engine power plants have been identified as being able to perform a lot of start-stop cycles, operate at high efficiency in part load and being flexible in the used fuel-types. The reaction time from command to full load is one to five minutes, big units consist of many small units on a modular basis. This modular character of engine power plants offers the possibility to fulfill different flexibility needs of the power system. Small-scale flexibility for grid stabilization as well as larger scale utilization of engine power plants have different values for the power system. Minimum load of heavy-duty gas turbines ranges between 20 and 40 percent of rated capacity, but with this high flexibility comes a loss in power plant efficiency of roughly 15 percent points when operating at minimum load. They have the lowest fixed cost, but especially at minimum load low efficiencies. When it comes to higher utilization rates at full load and less start-stop cycles, combined cycle gas turbines with high maximum load efficiencies (but higher fixed cost) are cost- and energy-efficient. Assuming even higher utilization rates, low carbon prices and low or medium shares of wind and solar, power plants operating with coal, lignite and nuclear steam turbines can provide the residual base load cost-efficiently. In future energy systems, the share of each technology should be adapted to the flexibility demands.

A quantitative analysis with the fundamental European energy market model Power2Sim helps to get a more precise picture of these flexibility needs: Fluctuating energy sources lead to increasing inflexibility in power systems, consequently, residual load needs to be more flexible than in the past. Until 2030, up to 30 percent of the feed-in of the national thermal generation capacities in Germany, France, Spain and Italy will need to ramp-up and down. Therefore situations that challenge the power system will become more normal. These results assume that interconnector capacities develop as planned and are open to the markets, and for example pumped-hydro storage capacities develop according to the scenario EU Energy Trends. According to this fundamental simulation of European electricity markets, for example in Spain, the 100 hours per year with the highest hourly load-ramps of thermal power plants will rise from 10 percent in 2015 to 22.5 percent of the thermal load in 2030. In Denmark, a country with a high share of wind energy, this value is already between 30 and 50 percent. During some hours in 2030 even 90 percent of thermal generation is ramped up. Subsequently, the amount of start-stop cycles will rise as well. We have seen 80, 38 and 56 (averaged historical values) cycles respectively in French, German and Spanish gas-fired power plants in 2015. It was found that in Germany power plants supplying daily peaks need to cycle 744 times in the year 2030 just in order to follow the hourly residual load. Supplying balancing energy and following price signals of intraday-markets are important factors for start-stop cycles as well. This could even increase the number of cycles.

The technical capability and the cost for cycling, ramping up or down and part load efficiency will become more and more critical parameters for power plants. Consequently, levelized costs of electricity depend strongly on the use case. For the remaining base load operation with full load hours of 6,000 and 90 percent of full load operation the averaged and levelized cost of electricity of coal power plants (54 EUR/MWh) and combined cycle gas turbines (49 EUR/MWh) are the lowest. The exact levelized cost depends on a power plant's individual efficiency and coal, gas and carbon prices. This use case is becoming less frequent due to the energy transition. Assuming a flexible usage of power plants (1,500 full load hours, 700 cycles and 50 percent of full load operation) levelized cost rises due to lower utilization of fixed investment and other fixed cost, due to start-stop cost and due to lower efficiencies in part load operation. For this use case the average and levelized cost of open cycle gas turbines rises (110 EUR/MWh) and engine power plants (86 EUR/MWh) have the lowest costs.

1 INTRODUCTION

The transition towards an energy system where the majority of energy will be provided by variable renewable energy sources (vRES) requires increased system flexibility. In Europe, the power sector already accommodates a high share of vRES and it is widely acknowledged that the further integration of those fluctuating power sources demands technologies and means that provide flexibility. A range of flexibility options, such as regular power plants, storage, increased power grid interconnections, demand-side-management (DSM) and power-to-gas (PtG) is promoted to meet the power system's requirements and to allow for uninterrupted supply of electricity. There is no flexibility application offering all the flexibility needs efficiently, it is a mix of different options which performs best.

Technologies that have the potential to provide flexibility to the power system are specified by their technical parameters. Parameters such as reaction time, electrical efficiency as well as power and storage capacity thus are important factors to analyse different types of flexibility sources. Next to the technical parameters that define the areas in which technologies are able to provide flexibility to the system, investment and operational costs are paramount to evaluate the economic viability of different flexibility options.

In this study different flexibility needs are identified and different existing and upcoming flexibility markets are described. This is followed by a detailed description of major categories of flexibility sources, their technical and economic characteristics are being compared to the different flexibility needs. Based on a comparison of reaction time, operation range, variable and fixed costs, the suitability and potential of each flexibility option is assessed. The economic valuation is complemented by a calculation of the average levelized cost of electricity for three different use cases from low flexibility and high utilization to high flexibility and low utilization.

In order to get a deeper understanding of the increasing demand for flexibility a system analysis of the residual load and load gradients of thermal power plants in five European countries follows. In this quantitative analysis the fundamental model for European energy markets Power2Sim is used. Another result of this analysis is the increasing need for start-stop cycles in future energy systems.

2 DIFFERENT FLEXIBILITY SOURCES FOR DIFFERENT FLEXIBILITY NEEDS

2.1 COMPARISON OF SYSTEM FLEXIBILITY NEEDS

Flexibility is not equal to flexibility. Different flexibility options ought to be deployed for different flexibility needs. First of all, the power system's need for flexibility is characterised by a time component. Regarding the time component, the lead time (time between the flexibility request and the flexibility delivery) and the duration (how long flexibility is needed) characterize short- and long-term flexibility. Different processes and needs of the power system contribute to different flexibility needs as shown in Figure 1.

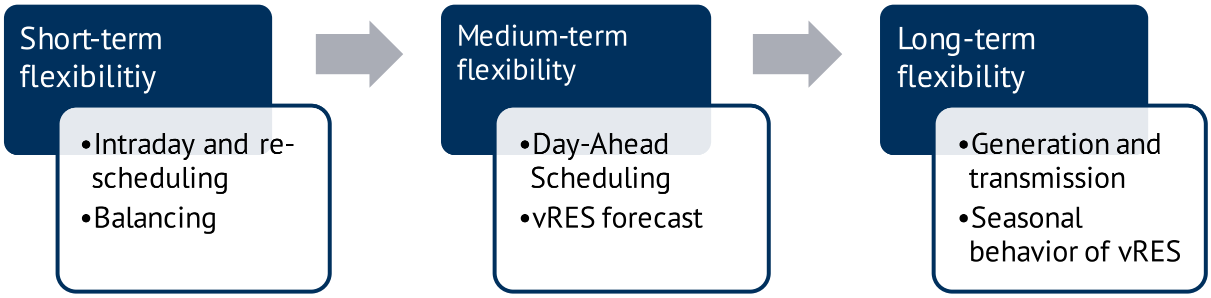


Figure 1: Flexibility timeline and relevant processes in the power market

Short-term flexibility is characterized by short lead-times and duration of up to hours. The driver behind this flexibility need is balancing generation and demand on a very short time scale for frequency and voltage regulation, congestion management and short-term imbalance management of balancing responsible parties. This is necessary mainly because of forecast deviations (vRES or demand), power-plant outages, steep load gradients and unforeseen events. In addition to active power provision, reactive power regulation needs to be considered. The main markets for this type of flexibility are balancing/control energy and intraday markets.

Medium-term flexibility can be seen as active power regulation following early vRES and demand forecasts in a time scale of up to a few days. Typically, day-ahead forecasts enable market actors to estimate the residual load – the load which has to be balanced by steerable technologies. Consequently, the lead time is longer than for short-term flexibility and ranges between hours and days. Typically, the day-ahead market enables activation of medium-term flexibility.

Long-term flexibility is needed for balancing the seasonal behaviour of vRES and demand. This flexibility need is getting more important with very high shares of vRES. Long-term flexibility is needed in time scales of weeks and seasons. As there are no reliable vRES long-term forecasts the flexibility need is estimated statistically and lead time is not a critical parameter for long-term flexibility needs.

Black-start-capability and island operation in case of system failure can be seen as flexibility needs of the system too. Black-start-capability means the ability of a power plant to recover from a shutdown of the power system. This is ensured by a few power plants that do not need external electricity to start. These power plants will generate electricity which is needed to re-establish the power supply independently. This kind of flexibility has short lead times, but long as well as short durations are possible.

The flexibility needs are detailed in Figure 2 along the flexibility timeline. The darker the respective colour, the more crucial a certain flexibility need is in terms of its lead time and/or duration. In the following, examples and explanations for the different flexibility needs from long- to short-term are provided. .

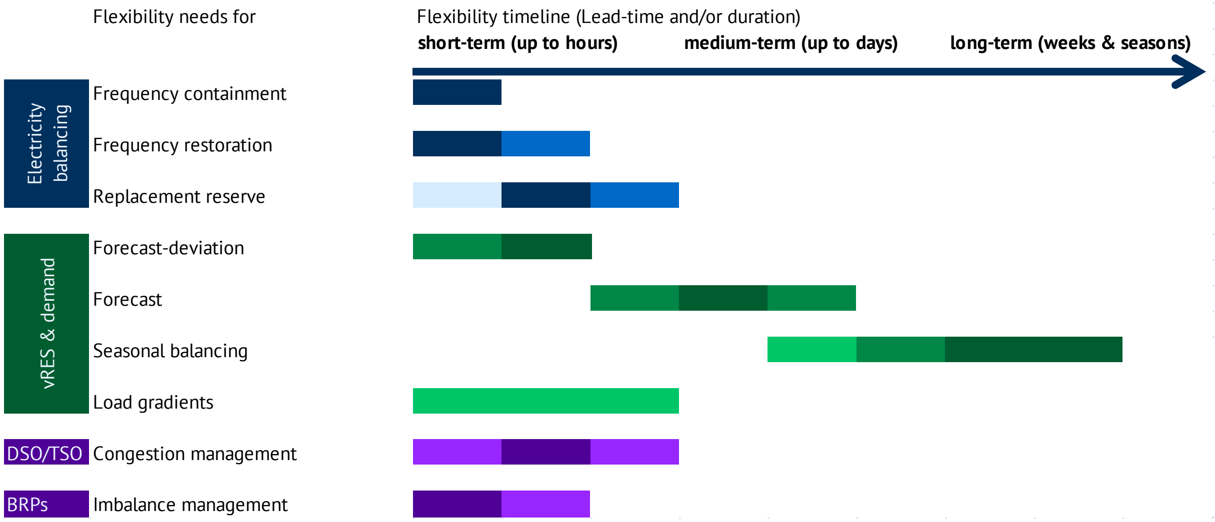


Figure 2: Flexibility needs along the flexibility timeline (vRES: variable Renewable Energy Sources, DSO: Distribution System Operator, TSO: Transmission System Operator, BRP: Balancing Responsible Parties), lead time is more important for short-term flexibility, duration is more important for long-term flexibility

Weeks and seasons ahead the feed-in characteristics of vRES need to be balanced: Model data for onshore wind feed-in (wind speeds of 1990 to 2015 and German wind capacities of 2015[1]) indicate that even when averaged over 31 days the generated load could fluctuate between 4

[1] (European Comission, 2016), moving average of 31 days of the wind onshore load factors in Germany. Connecting larger regions and offshore wind generation reduce this gap.

percent (summer 1994) and 61 percent (winter 2006/2007) of the installed onshore wind capacity. Weather forecasts and temperature-dependent demand forecasts can be used to estimate the need for medium-term flexibility and the dispatch of steerable technologies is managed accordingly. As a rule of thumb medium-term forecasts take into account the following three days. But even the standard deviation of day-ahead wind forecast errors amounts to 5.14 %, 5.34 % and 4.5 % of the installed capacity in Spain, Denmark and Germany, respectively[2]. Forecast errors of solar feed-in and demand further contribute to the magnitude of possible errors. If installed capacities increase faster than the forecast accuracy, forecast errors will have an even larger effect on the electricity system. Steep load gradients (medium-term to short term) of demand and solar can be foreseen day-ahead, while wind-driven load gradients go along with a shorter lead time. Usually duration time of steep load gradients for both solar and wind occur on the same timescale of up to hours. Following the day-ahead forecasts, the hour-ahead forecast's standard deviation decreases to 1.33 % and 1.16 % in Spain and Germany, respectively[3]. For about 44 GW of installed wind capacity in Germany 2015 the standard deviation of the forecast error reduces from 2.27 GW (day-ahead) to 0,59 GW (hour-ahead). Different actors have to cater for different flexibility needs in this situation, as can be inferred from Figure 2: Marketers of renewable energy need to sell or buy electricity according to the delta in forecasts. All remaining deltas need to be balanced out with frequency containment, frequency restauration and replacement reserves. System imbalances appear as well because of unforeseen changes in demand, interrupted feed-in of steerable technologies and other unforeseen events. The involved balancing responsible parties (BRPs) try to reduce the imbalance in their balancing groups in order to reduce cost for balancing energy provided by the transmission system operator (TSO). Additionally, distribution system operators (DSOs) and TSOs need local flexibility for congestion management and voltage regulation through reactive power.

2.2 FLEXIBILITY MARKETS

Different flexibility markets exist for different flexibility needs of the electricity system. Flexibility need is likely to increase with a higher share of vRES and some of the flexibility markets are still under development or changing.

[2] (Hodge, et al., 2012). The forecast quality has improved in recent years.

[3] (Hodge, et al., 2012). There is no hour-ahead analysis for Denmark in this source.

In all electricity markets, flexibility plays a role, where Figure 3 shows different flexibility markets along the flexibility timeline. The colours indicate the suitability of each market to provide products for different periods of time. A dark colour represents a fitting market for the respective product.

The classic markets for short-term flexibility are balancing markets and generally separated into three or four different sub-segments or steps: FCR/aFRR/mFRR/Reserve Markets. Markets are very different in the EU, where not all market segments are implemented in all national markets or are not comparable. The replacement reserve describes a reserve used to restore the required level of operating reserves with activation time from 15 minutes (in Continental Europe) up to hours. In many market designs like Germany, Belgium or Austria this is left up to the market itself, in others like France the TSO procures a tertiary replacement reserve.

A liberalized market for flexibility is the intraday market. It is characterized by up to 30 min lead time and down to product lengths of 15 minutes, generally the intraday-liquidity increases with the respective vRES-share. In general, liquidity in the hourly or quarter hourly day ahead market is much higher. Future markets with seasonal price differences exist and could be used for trading season price spreads.

New markets are regional markets, arising through decentral power plants and prosumers. Weather derivatives are common in other sectors and power exchanges just started to integrate them into their product families. First cap-products have been introduced on energy exchanges as well, supplying a hedge for extreme spot market prices in intraday markets. Insurances or reserve power plants may offer flexible load to balancing responsible parties to hedge high balancing cost.

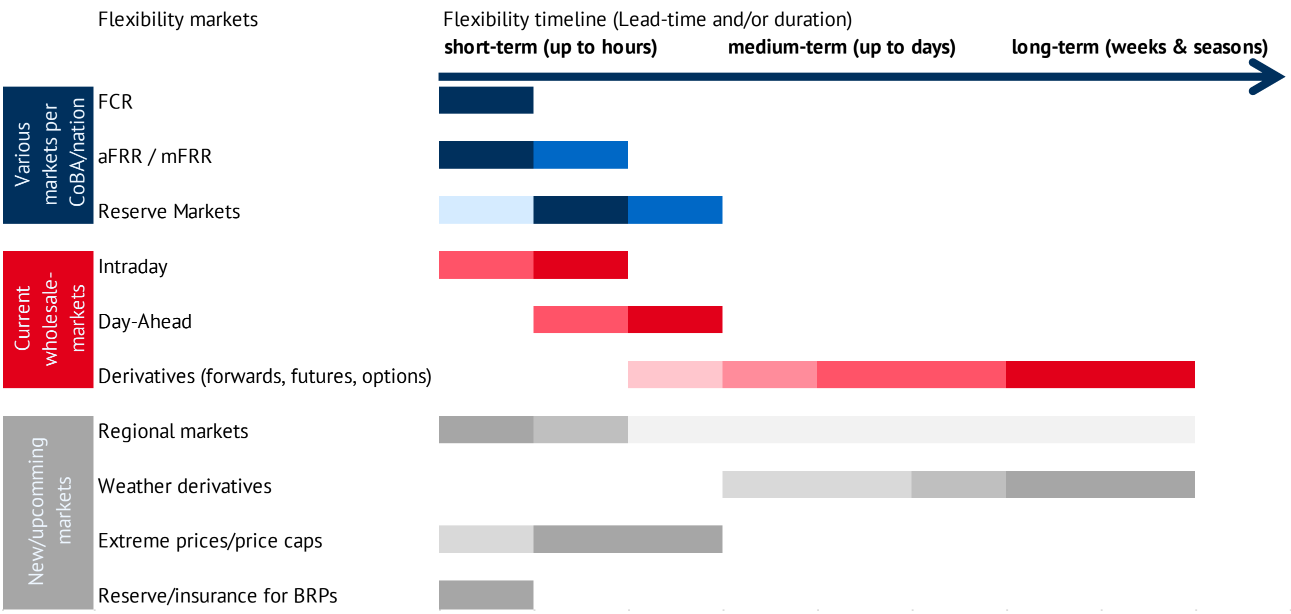


Figure 3: Markets for flexibility along the flexibility timeline (CoBA: Coordinated Balancing Area, FCR: Frequency Containment Reserve, aFRR/mFRR: automatic/manual Frequency Restoration Reserve, BRPs: Balancing Responsible Parties)

2.3 ASSESSMENT OF FLEXIBILITY OPTIONS

Depending on the type of flexibility needed by the power system, different technologies provide the respective flexibility requirements. Mapping the different options investigated below allows to compare them and to understand the value they provide to the power system along the flexibility timeline. Figure 4 shows selected technologies along the flexibility timeline. The darker the respective colour, the more eligible the technology is for providing short-, medium- or long-term flexibility. An explanation for the different technologies is provided below.

I. Supply

On the supply side both steerable and non-steerable technologies are available to provide flexibility. Furthermore, the flexibility provided by different types of power plants is not static, but depends on the current demand for flexibility and on the country where the respective power plant is located (e.g. nuclear power plants in France will have a different future than nuclear power plants in Germany). Power plants characterized as inflexible can achieve greater flexibility (to a certain extent) if necessary. Additionally, different types of flexibility can be provided at specific load-levels.

A fundamental aspect has to be considered when analysing various methods available to provide flexibility: To ensure a secure operation of the electricity grid the residual load has to be covered at all times. Therefore, conventional power plants have to provide the difference between the entire demand for power and the power produced by variable renewable energy sources at any given point in time. The problem is the following: Thermal power plants are not able to provide arbitrary amounts of power between zero and their maximum load, meaning the load cannot fall below an individual must-run capacity due to different reasons: Some power plants will not shut down completely because they need a long period of time for starting again and shutting the plant down increases the wear on the components. Plants that combine heat and power production may not be able to reduce the amount of electricity generated because the heat is needed, for example for heating purposes in industrial processes. Additionally, the TSOs have to determine an amount of must-run capacity because a certain amount of power is needed for ancillary services such as providing reactive power or having capacities available for control energy. In the design of the present energy system the residual load drops below the must-run capacity even more frequently due to the increased expansion of vRES. Therefore, the surplus power needs to be exported, stored, used for different purposes or vRES have to be curtailed (in this case their operating costs are not reduced). Exchanges even record negative prices caused by these overcapacities.

a. There are a lot of different technologies using steam turbine power plants with different characteristics:

   Power plants fueled with lignite and nuclear power plants are used for base-load operation as they have the advantage of low short-run marginal costs. Therefore, they can be used for providing long-term flexibility, for example for a couple of weeks of high demand in winter. Nevertheless their utilization is limited due to high emissions or other environmental risks, as well as due to high fixed costs. It is discussed to use carbon capture and storage (CCS) in order to reduce the amount of emitted greenhouse gases for lignite and coal technologies, but economic, technical and environmental risks still exist.

   Coal-fired steam turbine power plants are more flexible in terms of their minimum and maximum load and are able to run on a lower load level. They are able to go through more operating cycles (up to a daily basis), but are limited by higher short-run marginal costs and high emissions as well.

   Due to the environmental policies of the European Union it is highly probable that without CCS or Carbon Capture and Utilisation (CCU) the competitiveness of lignite and hard coal power plants will decrease. Only small quantities of renewable fuels that are feasible for firing steam turbine power plants are available (such as solid biomass or waste).

Steam turbine power plants are being used for the provision of short- and medium-term flexibility to a certain extent. For example, they can vary in 1 to 2 % of their capacity (both positive and negative) for balancing. This short-term flexibility is restricted by the fact that it adds inflexibility and must-run capacities to a future energy system based on vRES.

Combining the production of heat and power in one power plant (CHP) increases the overall efficiency of steam turbine power plants but it reduces the short-term flexibility at the same time. Heat storage or the usage of power-to-heat technology is able to recompense fo this shortcoming and bring back short-term flexibility (the time-scale depends on the respective heat storage capacity).

b. Gas Turbines (Open Cycle Gas Turbines OCGTs and Combined Cycle Gas Turbines CCGTs) offer the bulk of short- and medium-term flexibility at the moment. The efficiency of OCGTs is relatively low but they can react comparably fast, meaning this technology is able to adapt its load quickly.

   At full load, CCGTs have the highest efficiency of all types of thermal power plants. Their reaction time is slower compared to OCGTs, additionally, they suffer from efficiency-losses at minimum load. The level of short-run marginal costs highly depends on the future prices of both fuel and emissions. Depending on commodity prices CCGTs provide long-term flexibility as cost-efficiently as steam turbines.

   Gas turbines are limited by the characteristics of the used fuel, because natural gas is a limited domestic resource for most countries in Europe. The availability of natural gas (or suitable oil) is linked to political and economical risks. The import of natural gas is expensive due to high transport cost and can be impaired if conflicts arise. Using natural gas as a fuel also causes emissions of greenhouse gases. On the other hand, gas turbines are more adaptable to renewable fuels than steam turbines because in the future a surplus of electricity may be converted into a suitable fuel by using the power-to-gas or the power-to-liquid technology.

   It is possible to improve the overall efficieny of gas turbines by combining the production of power and usable heat in one power plant (CHP). This process however limits the short-term flexibility of the power plant and causes a must-run capacity . This problem may be resolved with heat storages and/or power–to-heat.

c. Gas-fueled engine power plants have the advantage of providing short- and medium-term flexibility without causing must-run capacity. Smaller units may be built modularly and are able to undergo many start-stop cycles without additional wear and additional damage. Another advantage is the fact that the efficiency is independent from the load-level of such a modular power plant. There are engine power plants that can use a variety of fuels: They may be fueled with renewable fuels and the technology may be adapted to the combustion of hydrogen. Engine power plants are able to perform black-starts and can be installed in a decentralised way. Today the technology is limited by the fuel constraints of natural gas as well. The technical characteristics of engine power plants make it a suitable technology for providing short-term flexibility. Though being technically able to provide both, long-term and short-term flexibility, the goal of saving fuel an reducing emissions favours CCGTs regarding long-term flexibility. The reason for this is that the full-load efficiency of engine power plants is lower than the efficiency of a CCGT. Additionally, when considering full load NO_x-emissions are higher in engines than in turbines. This picture changes when considering part load operation and a high amount of start-stop cycles. Average efficiency and emissions of engine power plants is considered to perform better in such a use case.

d. Providing flexibility by reducing the feed-in of variable renewable energy sources may be used for balancing in extreme situations: Curtailing vRES can reduce grid cost or limit oversupply in the far future. This option comes with a very low system efficiency and very high costs.

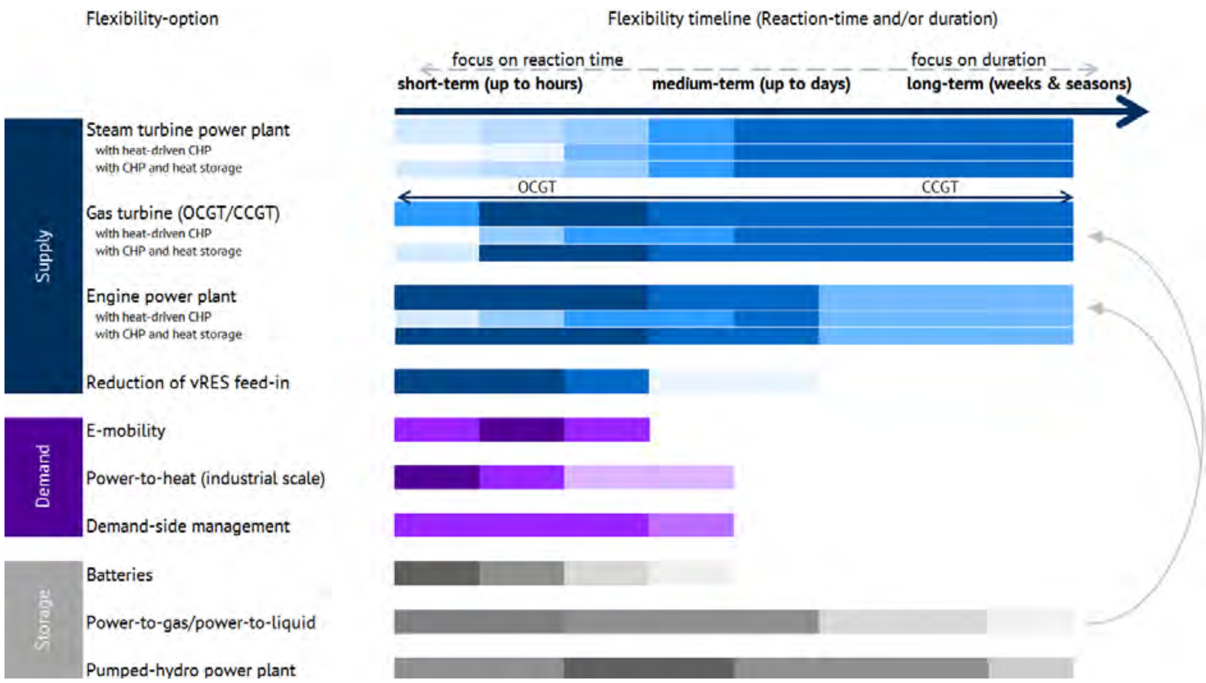


Figure 4: Flexibility options along the flexibility timeline (CHP: Combined Heat and Power, OCGT/CCGT: Open/Combined Cycle Gas Turbine, vRES: variable Renewable Energy Sources)

II. Demand

Until today the majority of the electricity demand is inflexible. If the demand becomes more flexible, the overall system cost will be reduced. Increased flexibility can be achieved by sector coupling, for example in form of electrification of the mobility and the heating sector. There are various forms of developing flexible demand:

a. Integrating electric vehicles in the electricity grid can provide short-term flexibility because the installed batteries usually undergo daily cycles of charging. Connecting a large amount of electric cars provides flexibility. However, habits of the user limit this approach because they might also cause inflexibility at the same time: Using electric vehicles generates additional electricity demand. During a typical week, at least 40 percent[4] of all passenger cars are immobile and could be plugged in, bidirectional charging of batteries can be established in the future, but is again restricted by the drivers' requirements.

b. Converting surplus power to heat improves short-time flexibility of a CHP power plant and reduces must-run capacity or the need for curtailment of vRES. Even though this process has a low overall efficiency, it is still better to use an inefficient

[4] Own calculation, Energy Brainpool

method to utilize electricity from vRES without short-run marginal costs than to curtail it. Coupling the heating sector and the electricity sector can provide flexible short-term demand by using heat-pumps in combination with heat networks and heat storages. On the other hand, power-to-heat causes a more temperature-dependent electricity demand in the long run, as more capacities will be needed in winter than in summer. While providing short-term flexibility, it increases the demand for long-term flexibility.

c. Demand-side management can be divided into households and industry. By reducing or shifting load, it is possible to provide short-term flexibility. In order to realise this approach on an appropriate scale in households, it is necessary to aggregate smaller units. Such an aggregation is clearly aided or even only made possible through increased digitalisation. For Germany the potential for reduction of demand is 0.6 GW in households and 2 GW for industry and commercial applications[5]. Increasing the demand is easier, where the potential in Germany amounts to 2.3 GW and 4.4 GW for households and industry/commercial applications, respectively. Demand-side management through sector coupling of the heating sector offers a huge surplus potential.

III. Storage

Storage capacities are able to provide both, demand and supply. Different storage technologies for different time-scales are available and new technologies for the storage of electricity are being discussed in academia. Here, we focus on existing technologies.

a. Batteries: Lots of different battery-types with various characteristics exist. Most batteries have a small storage capacity (MWh) but large capacity in MW. This fact and the self-discharge of some technologies and economic aspects are the reasons why the majority of batteries is used for short-term issues. It has to be taken into account that battery technology is characterized by a steep learning curve and that the future potential of specific technologies is not entirely clear yet. In lifetime or lifecycle asessements a large part of battery-technologies are being challenged, as they use materials causing environmental degradation.

b. Converting surplus power into gas or liquids (these forms can be stored or used differently) is the only available, scalable technology that balances volatile

[5] (Fraunhofer-Institut für Windenergie und Energiesystemtechnik, Energy Brainpool, 2015)

production of vRES seasonally without causing additional emissions. The technology produces storable renewable fuels which can be used in gas turbine power plants, engine power plants, fuel cells or in both the heating and the mobility sector. The efficiency of involved processes is low however: Converting electricity to hydrogen, then to methane and then back to electricity results in an overall efficiency of 30 to 50 percent. Using this method to utilize surplus electricity provides short- and medium-term flexibility. In the future energy systems with very high shares of wind, these conversion technologies could provide long-term flexibility in weeks with high wind feed-in. Flexibility characteristics of re-using the produced fuels for electricity production depend on the respective power plants which are used, as discussed in the paragraph on supply. The future of this technology is not clear yet, as a steep learning curve is necessary to reach economical feasability and currently there is a lack of investments into this technology.

c. Pumped-hydro power plants are used to store power for time periods of up to days. Reservoir hydro power plants (plants without pumps) are also used for long-term storage. In the future it may be possible to make use of the complete European potential (i.e. in Norway) as a highly efficient European storage medium that can provide long-term flexibility. In comparison with other energy storage technologies, reservoir hydro power plants are a mature and cost-efficient technology. The capacity is limited by geological and geographical conditions.

2.4 POTENTIAL OF FLEXIBILITY OPTIONS

Different flexibility options along with their potentials and along with the residual load as an indicator for the flexibility demand are depicted in Figure 5. The three curves show the residual load curve of a system with a low, medium and high share of wind and solar. The residual load demonstrates how much electricity needs to be provided by steerable load. For reasons of generalization and comparability, the vertical axis is depicted on a relative basis. One can imagine a power system that has a maximum load of 100 GW and a maximum residual load of 100 GW as well (wind and solar feed-in can be close to zero in the hours of maximum load). In Figure 5 France 2015 represents the case “low share wind & solar”, Germany 2030 represents “medium share wind & solar” and Denmark 2030 represents the case “high share wind & solar”. Thus, the development from the dotted over the dashed to the solid green line is characteristic for the prospective development of European electricity systems. The dimension of flexibility options displayed focuses on the system representing a high share of wind and solar (the solid green line). Existing and planned flexibility sources like import/export or pumped-hydro power have been considered during the calculation of the respective residual load curves. There are only very few hours, when 80 to 100 percent of steerable load is needed – a power plant would run only very few hours to meet this demand. In order to prevent expensive and rarely used capacity, demand-side management and batteries could provide this flexibility in these extreme situations with high demand and low solar and wind feed-ins. This is shown on the right hand side of the figure. Today it is not clear, how big the future potential for demand-side management will be, as this depends a lot on the penetration of emerging technologies like E-mobility and heat pumps. From the left of the figure towards the right different levels of residual load may be assigned to increasing utilization rates. They are differentiated according to the necessary amount of steerable loads. Consequently, on the right-hand side flexibility options are sorted from top to down according to their capability of providing flexibility for the respective residual load and utilization rate. From the top residual load (light grey) has low utilization rates depending on the share of wind and solar (green residual load curves) but high capacities (40 to 75 % of maximum residual load). For this demand of steerable load, power generating capacity should be cheap and have short reaction times, which is the case for OCGTs and engine power plants. The shown utilization rate is up to 30 percent (2,600 hours a year) for a power system with high share of wind and solar (dark green residual load curve). In systems with a lower share of wind and solar this range is much smaller. They need to change their power output very often and face a lot of start-stop cycles. In the range of about 20 to 40 percent of maximum residual load (utilization rate is 30 to 75 percent of a year) variable cost and full load efficiency are becoming more important, which is why CCGTs are assumed to be an efficient option. There is only a little demand of up to about 20 % of the maximum residual load (dark grey) which is efficiently supplied by steam turbines (coal, lignite, nuclear) with high full load hours and a lower amount of start-stop cycles. If carbon prices rise and lead to a fuel switch or environmental policies restrict coal, lignite or nuclear power plants, CCGTs would replace coal and lignite fired power plants.

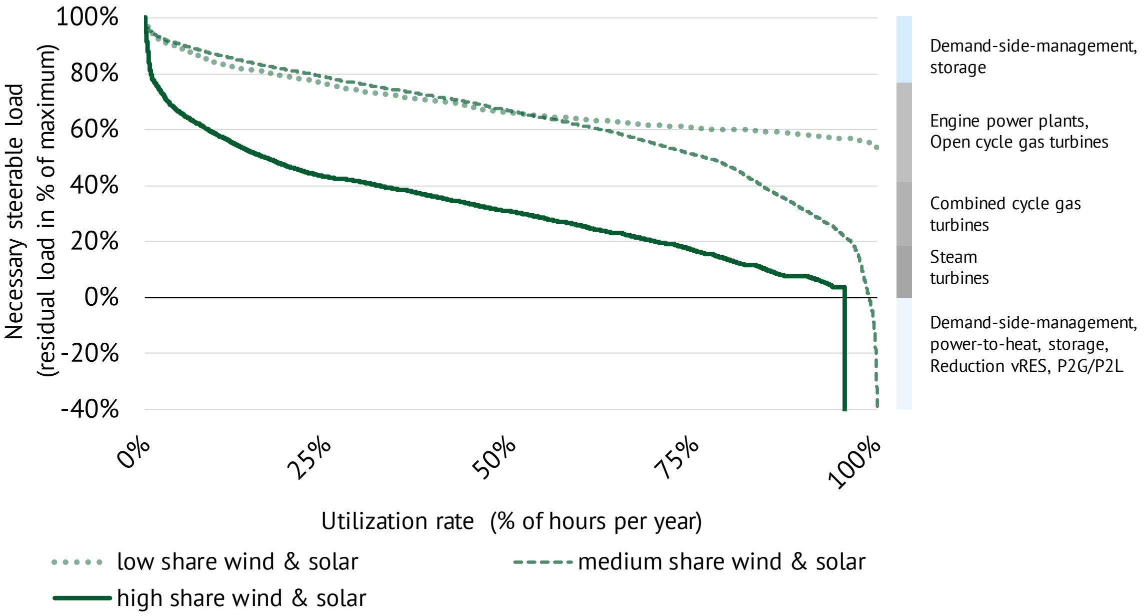


Figure 5: Exemplary analyses of potentials for flexibility options following the sorted hourly residual load curves of power systems with a high (solid), medium (dashed) and low (dotted) share of wind & solar.

In systems with a high share of solar and wind there will also be hours with an oversupply, which is not being consumed by “classic” consumers. As the shown curve is a modelled residual load curve from the European power model Power2Sim, already considering imports/exports, this feed-in represents a real surplus of electricity. More demand-side management, batteries, power-to-heat or electrolysers could use a share of this electricity but the residual is wasted by reducing wind or solar feed-in.

2.5 COMPARISON OF FLEXIBILITY OF POWER PLANT TECHNOLOGIES

Besides demand-side management, E-mobility, storage technologies and Power-to-X applications, flexible generation will be necessary in future electricity systems for guaranteeing reliability of supply. In this study, we considered six different dimensions of flexibility for power-supplying technologies. Nuclear, lignite and coal power plants – though having different performance – form one category of steam turbine power plants for the sake of simplicity. For a detailed description, please compare chapter 2.3. In Figure 6 we compare the flexibility characteristics of steam turbines, CCGTs, OCGTs and engine power plants qualitatively from today's perspective, where a more detailed deliberation on the different flexibility characteristics can be found below. A point close to the outer line represents a valuable flexibility-characteristic. Also, flexibility characteristics of demand and storage are characterised in general.

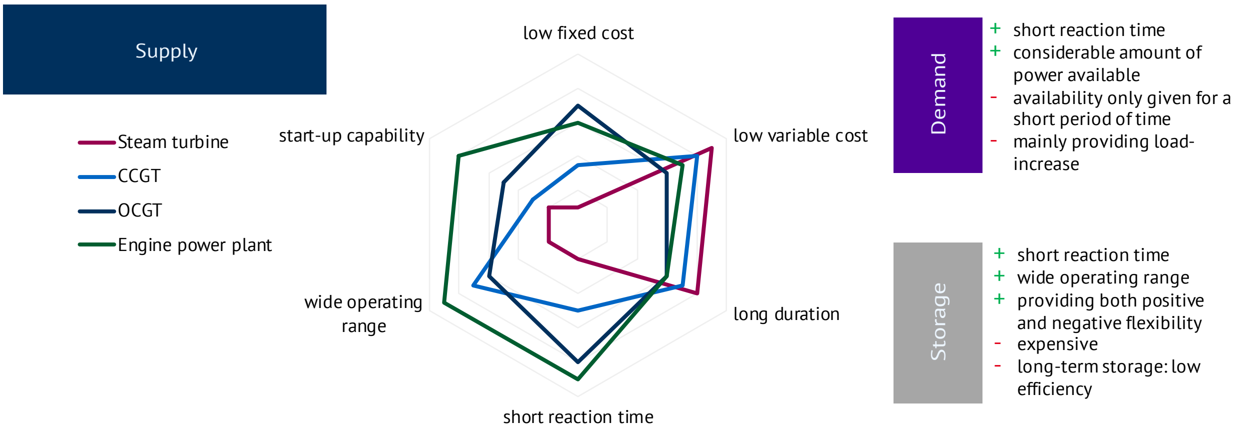


Figure 6: Visualisation of parameters characterising the flexibility of selected providers of flexible and steerable generation

- **Short reaction time:** A short reaction time enables a power plant to provide flexibility quickly. The start-up time from ramp-up command to full load is only a few seconds or minutes long.
  As changes in wind and solar forecasts and outages of power plants are at times sudden events, quick availability of a flexibility option is an important criterion. A detailed view on reaction times of all flexibility sources is given in Figure 7. Of all generation technologies engine power plants are quickest (one to five minutes from command to full load), followed by gas turbines (approximately six minutes), in a CCGT the secondary steam turbine follows after 30 to 240 minutes. In comparison, the steam turbines have much longer reaction times: A hot or warm start of a coal-fired power plant is in the range of one to 10 hours,

depending on the respective technology. A cold start of nuclear power plant can take several days.

- **Wide operating range:** A wide operating range is a characteristic of power plants with low minimal loads. Such a power plant is able to run on a small proportion of its maximum load. High efficiencies at minimum load are beneficial for a flexible operation as well. Modularity further increases flexibility in the operation range. According to an EUGINE questionaire among its members, the minimum load of single engine power plants typically is 30 percent, especially when built as smaller units of for example 20 x 4 MW, where the total amount of 80 MW can be operated by steps of 4 MW at maximum load of the single engines, the calculated theoretical minimum load then would be 1.2 MW or 1.5 % of the total capacity of the modular 80 MW engine power plant. Concerning OCGTs a distinction between heavy-duty and aero-derivative gas turbines is important. At full load aero-derivatives generate power with more or less the same flexibility and modularity as engines but their part load capabilities are substantially worse than the part load capabilities of engines. Those are smaller units with high load gradients. Heavy-duty gas turbines for electricity generation however are typically big units with less flexibility. Minimum load ranges between 20 and 40 %, but with lower minimum load comes a loss in power plant efficiency of roughly 15 percent points. A modular concept is not typical for units with high capacities. CCGTs consist of gas and steam turbines, which reduces flexibility in operation. The overall operation range is in the range of 50 percent of maximum load, but minimum load can be reduced down to 30 percent, as for the steam turbine the load gradient is not as steep as the one of a gas turbine. Existing steam turbine power plants have a minimum load of about 50 percent (lignite) and 40 percent (hard coal), where new or repowered units already possess lower minimum load. The operation range of nuclear power plants depends on the respective plant's design choice, and are not considered in this study.
- **Start up capability:** A strong start-up capability means the power plant is able to perform many start-stop cycles in a short amount of time without being compromized.
  According to an EUGINE questionaire among its members no surplus operation and maintenance cost occur with up to one thousand cycles per year. This is different compared to most other technologies. In literature values of 43 and 46 EUR/MW per start-stop cycle are given for OCGTs and CCGTs, respectively. A coal-fired power plant has costs of 84 EUR/MW per cycle, while the total amount of cycles is limited technically as well.

- **Low fixed cost**: Low fixed cost describes power plants having low capital expenditures (CAPEX) - including financing costs and fixed operational expenditures ($OPEX_{fix}$) - compared to other types of power plants.
  Power plant capacity is a big cost factor. Averaged literature values for annualized fixed cost for a coal power plant (as the typical example for a steam turbine) are 159.6 thousand EUR/(MW a) and for CCGTs 90.2 thousand EUR/(MW a). OCGTs and engine power plants are in the same range of 51.8 and 59.2 thousand EUR/(MW a), the latter value represents an average, according to a questionnaire of EUGINE among its members. For a detailed analysis compare Table 2. An examplary calculation gives an idea of the potential impact on power prices in times of high residual load: if a power plant was used only for 500 hours a year, a coal-fired power plant would need to earn more than 300 EUR/MWh only to pay the fixed cost, for an OCGT this value is close to 100 EUR/MWh.
- **Low variable cost**: Low variable cost are characterized by low operating costs, i.e. such a power plant has little expenditures on fuel, carbon and variable maintenance (OPEXvar).
  How variable cost are calculated is changing along with the energy transition. The classic view stipulates that depending on commodity prices for the respective primary energy source as well as carbon prices on the one hand and electrical efficiency on the other hand. The short run marginal cost differ from power plant to power plant. Taking into account today's low carbon prices and the coal-gas price spread, coal-fired technologies have favourable variable cost. Higher carbon prices would promote a fuel switch, where CCGTs with higher efficiency and lower emissions have more favorable, that is lower variable, costs. This classic view is depicted in Figure 6.
  In addition to this classic view, consideration in a future electricity market need to take into account that an increasing share of wind and solar will go along with a higher share of partial-load operation and more start-stop cycles. Assuming a lot of start-stop cycles and frequent partial load operation, the variable cost of steam turbines and CCGTs rises. For a detailed analysis of this development please compare Figure 9.
- **Long duration**: The category long duration stands for the suitability to provide the required amount of energy for a longer period of time, even up to weeks or seasons.
  All regarded technologies are capable of providing power for a long period with high reliablity. Assuming a long duration per operation, start-stop cycles are less relevant and low short run marginal cost is the most important criterion for the suitability of a

technology to provide power with long duration.

2.5.1 TECHNICAL CHARACTERISTICS

The reaction time of different flexibility options is detailed in Figure 7. The quickest option is battery technology, which can react within milliseconds. Batteries therefore provide frequency containment reserve and enhance the quality of electricity supply. Demand-side management and the reduction of vRES have a reaction time of a few seconds up to 5 minutes, while a pumped-hydro power plant's reaction time is slightly slower with values of 25 seconds. Engine power plants provide full load within one to five minutes from command. OCGTs, CCGTs and different steam turbines follow as described in chapter 2.5 above.

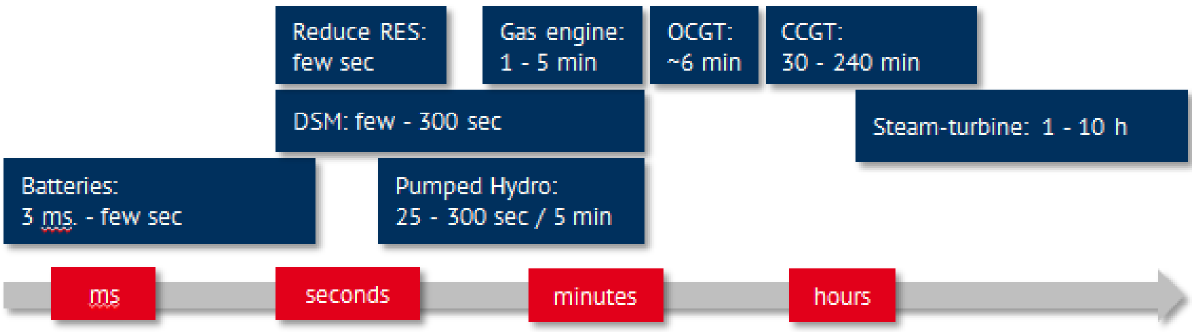


Figure 7: Reaction time from command to full load of selected flexibility options

Thermal power plants operate within their possible load levels. At maximum power the efficiency is highest, whereas at minimum load efficiency is lower. Accordingly, decreasing efficiency translates into an increase of emissions and fuel input. Figure 8 shows the operation mode of French, German and Spanish gas-fired power plants in 2015. The hourly data for power production is sorted from high to low and is presented as relative values according to their maximum load. Only such power plants have been selected for this analysis, where hourly data exist for more than 8,000 hours in the ENTSO-E transparency platform. Those 30 power plants have been assigned to one of three different operation modes. The blue lines represent an on/off operation mode, if the power plant is running, it is operating at or close to maximum load. Most of the evaluated gas-fired power plants have low operation rates, none is running in more than about 25 percent of the hours. The red lines represent a partial load operation mode, and in comparison to the on/off operation these power plants are running in more hours of the year (up to 80 percent) and most of the time in partial load. A lot of those power plants have a minimum load of about 40 percent, below this load factor they switch off. The reason for this operation mode can be a CHP-operation. Their effective electrical efficiency is far below the rated capacity at maximum load. Other operation modes which do not fit in one of these two pictures are assigned to the third operation mode, where many apparently operate on specific load levels, especially the minimum load. Thus, they face a barrier to go under specific load levels indicating a technical inflexibility. These load levels could be the minimum load of specific blocks of a power plant. Start-stop or downtime costs are hurdles and do not allow an operation under these minimum load levels.

Summing up, for the on/off operation mode, quick load gradients and cheap capacity cost are important flexibility parameters. For partial load operation high efficiency at partial load or modularity is crucial, in the category “minimum load/other” the power plant’s operation mode is restricted by downtime cost and discrete levels of minimal load.

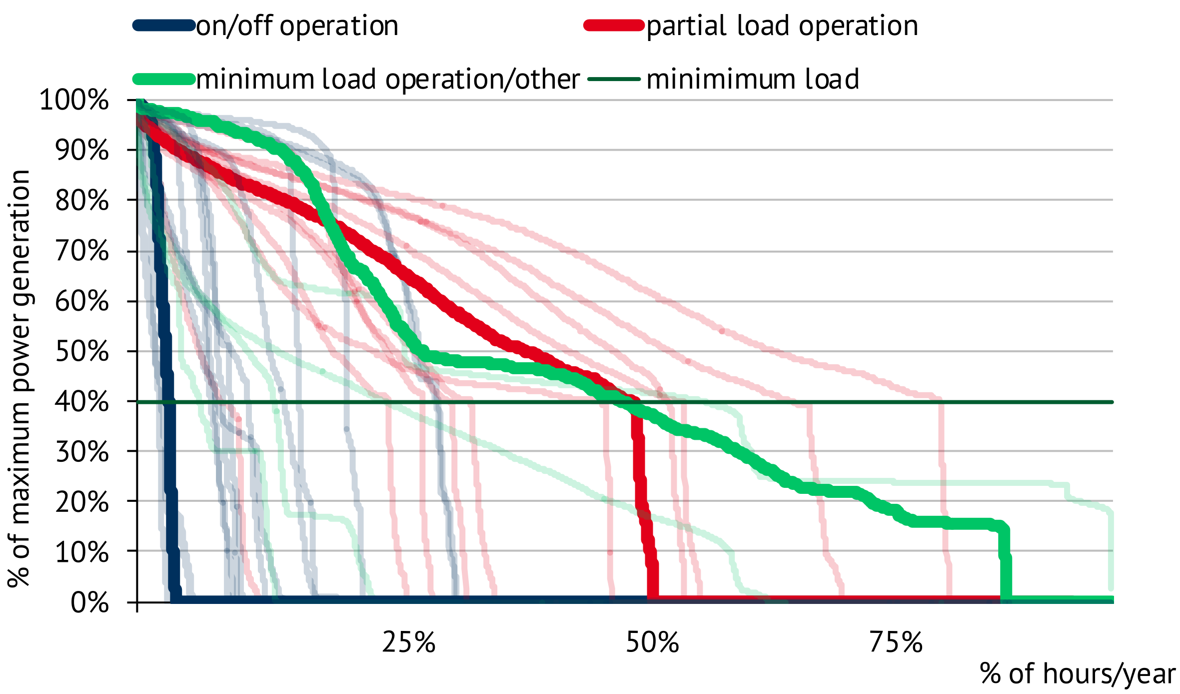


Figure 8: Sorted annual load curves of three characteristic operation modes and of in total 30 gas-fired power plants in France, Germany and Spain (Source: EEX, Entsoe)

Figure 8 shows that gas-fired power plants operate in partial load very often, so, it is important to judge the efficiency of a flexible power plant not only by its full load efficiency. Typical values for minimum load efficiency and suitability for modular construction are given in Table 1.

Table 1: Typical, minimum and maximum values for the electrical efficiency of thermal power plants, source: values of a literature survey (details on page 40ff) and EUGINE questionnaire, pp: percentage points

	efficiency drop at minimum load	full load efficiency	modularity
Coal power plant	-7 pp (5 – 9 pp)	45 % (32 – 54 %)	-
Open cycle gas turbine	-15 pp (10 – 20 pp)	41 % (35 – 45 %)	aeroderivatives: yes
Combined cycle gas turbine	-9 pp[6] (7 – 11 pp)	59 % (50 – 65 %)	-
Engine power plant 1 - 4 MW	-4 pp	45%	1-20 units per site
Engine power plant 10 MW	-4 pp	49%	

The efficiency drop of coal power plants is 7 percentage points, for OCGTs 15 percentage points. CCGTs face a high efficiency drop at minimum load of about 25 percentage points, when operating at for example 30 percent of maximum load in gas turbine solo operation. Consequently, CCGTs do not operate at their minimum load. When operating at 50 percent of maximum load, the electrical efficiency of CCGTs stands at about 50 percent. Engine power plants are characterized by comparably high efficiencies at minimum load, where the efficiency drop is only 4 percentage points. Aeroderivatives (gas turbines) or micro gas turbines and engine power plants can be constructed modularly and a variable number of engines / micro gas turbines can operate each at full load with full load efficiency.

2.5.2 ECONOMICAL CHARACTERISTICS

Technologies that have the potential to provide flexibility to the power system are not only specified by their technical parameters. Next to the technical parameters, investment and operational costs are paramount to evaluate economic viability of different flexibility options. Only the combination of technical and economic parameter allows a holistic definition of the areas in which technologies are able or suitable to provide flexibility to the electricity system. Table 2 indicates technical and economic parameters of different flexibility options. There are three

[6] This value describes a minimum load of about 50 percent of full load, but a CCGT power plant may be operated at lower load levels in solo gas turbine operation mode with very high efficiency drop of about 20 –30 pp.

cost categories: capacity, usage and flexibility. Fixed capacity cost (CAPEX and $OPEX_{fix}$) occur without strong dependencies to the usage rate. Usage cost are short run marginal costs at full load and variable OPEX, depending on efficiency, commodity prices and individual parameters of the power plants (e.g. age, maintenance contract). The third cost category reflects the cost for providing flexibility, so downtime / cycling cost and short run marginal cost at minimum load. Variable OPEX occur as well, as no specific data were found we assume the same variable OPEX in flexible operation as we did in the usage case.

Table 2: Technical and economic parameters of different selected flexibility options (Source: averaged values of a literature survey). SRMC stands for the Short Run Marginal Cost (Fuel and CO_2)

Cost category	Capacity			Usage		Flexibility		
	CAPEX		OPEX fix	SRMC full load	OPEX var	Downtime cost	SRMC at minimum load	OPEX var
	EUR/kW	EUR/ (MW a)	EUR/(MW a)	EUR/MWh	EUR/MWh	EUR per start-stop cycle and MW	EUR/MWh	EUR/MWh
Coal power plant[1]	1,643	112,866	36,776	25	2	84	28	2
Open cycle gas turbine[1]	468	39,664	8,068	44	5	43	57	5
Combined cycle gas turbine[1]	803	63,821	22,187	31	2	46	44	2
Engine power plant 1-4 MW (modular)[2]	500	46,694	12,500	40	6	0	44 (40)	6

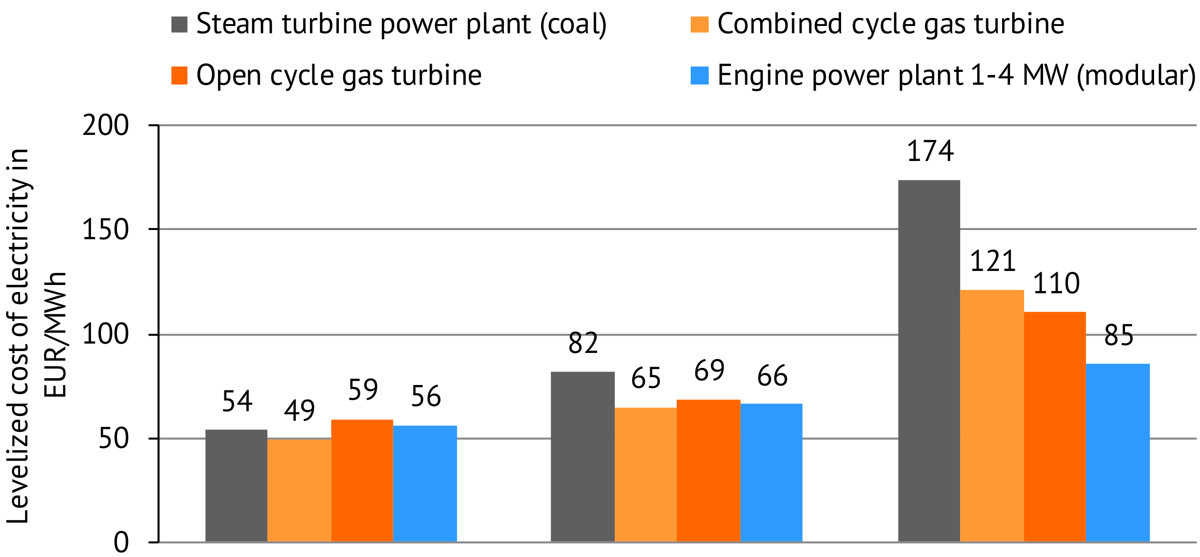
I. Steam turbines are cost efficient with high usage/full load hours and low flexibility demand
II. CCGT are cost efficient with medium usage when operated at full load and with medium flexibility demand
III. Engine power plants are cost efficient for supplying flexibility (ramping, start-stop cycling) with medium/low operating hours

[1] Derived from a metaanalysis of 17 studies, median values, WACC of 6,86 %, coal price of 70 USD/t, gas-price of 17 EUR/MWh, EUA-price of 5 EUR/MWh, liefetime of 30/25/20 years for coal (CCGT/OCGT)

[2] Data source for CAPEX, OPEX, efficiencies and downtime cost: EUGINE questionaire among the members, economical lifetime of 20 years

The levelized cost of electricity generation depends on the use case. Fixed capacity cost are less important than commodity prices and a high rated efficiency when usage is high at maximum load. With low usage rate and a lot of operation at partial load low capacity-bound cost and low flexibility cost are important. A comparison is achieved by means of three different use cases, depicted in Figure 9. Here, from left to right flexibility and usage requirements change for power plants through the energy transition and high shares of wind and solar. The respective levelised cost of electricity can be seen in the bar chart.

When it comes to high usage rates CCGTs and coal power plants are more cost-efficient than OCGTs and engine power plants. Depending on the coal/gas price spread, carbon prices and the exact amount of full load hours, either CCGTs or coal power plants show lower levelized cost. The lower the full load hours, the less competitive are coal fired power plants due to their high fixed cost. Levelized cost of electricity rise for all power plant types when full load hours decrease. However, the effect is highest for technologies with high fixed cost. The order of levelized cost of electricity generated by CCGTs and engine power plants depends on the exact amount of full load hours (CCGTs with lower usage cost or engine power plants/OCGTs with lower fixed cost). The third use case is characterized by 1,500 full load hours, 50 percent of full load operation and 700 start-stop cycles. Higher minimum load efficiency and low or no cost per cycle lead to the levelised cost of electricity of 85 EUR/MWh for engine power plants, 110 EUR/MWh for OCGTs and 121 EUR/MWh for CCGTs. Most of today's coal power plants are not built to perform 700 cycles a year, so 174 EUR/MWh is a rather theoretical value. As the calculation was done with averaged literature values, specific power plants of each technology may perform better or worse.



	high usage low flexibility	moderate usage medium flexibility	low usage high flexibility
Full load hours	6000	3000	1500
% full load operation	90%	90%	50%
Amount of start-stop cycles	5	50	700

Figure 9: Levelized cost of electricity depending on character of operation (usage/flexibility), Different use cases for the operation of power plants, high usage with low flexibility (coal power plants today), moderate usage with medium flexibility (gas-fired power plants today) and low usage with high flexibility (use case for flexible power generation in the future)

3 MODELLING THE DEMAND FOR SYSTEM FLEXIBILITY

The transition towards renewable energy sources requires considerable capacities which are able to ramp up and down fast in order to counterbalance fluctuating feed-in of vRES. An example of how fast flexibility options have to be able to accommodate changing power from vRES was the solar eclipse in 2015. Figure 10 exemplifies this need for fast reaction times for ramping up and down during short periods of time. During the solar eclipse in Germany there was a solar gradient of 18 GW within one and a half hours, meaning that steerable power plants had to reduce power generation by 18 GW. Some power plants had to start up in order to operate for the solar eclipse. In a European power system with a rising share of vRES this is ever more important. What was a very special situation in 2015 will become a common situation on sunny days as solar capacity increases. The graph on the right-hand side of Figure 10 shows a similar situation during a situation with a high drop of wind feed-in in December 2023 in Germany (after the nuclear phase-out in 2022) according to the results of a fundamental simulation in the energy market model Power2Sim. A residual load gradient of 45 GW occurs within a few hours.

It is thus necessary to have technologies available which have technical characteristics that coincide with the required needs for flexibility. In this chapter this demand for system flexibility is analysed and – where possible – quantified.

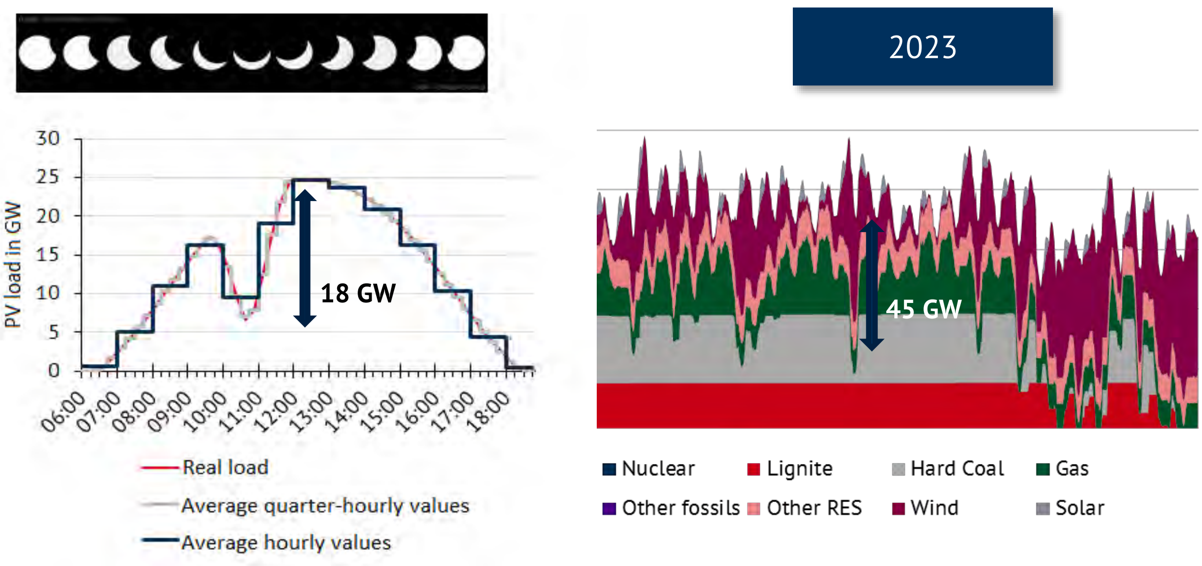


Figure 10: Short-term technical flexibility needs. Solar eclipse of March, 20th 2015 (left) and during the month of December in 2023 in Germany (right)

The examples given in Figure 10 are two examples, in order to understand the impact of the energy transition on required load gradients of residual power plants. An important question therefore is: How often will such load gradients occur and how high will such load gradients be in different European countries? We conducted an hourly fundamental energy market simulation, where details of the model and input parameters are given in the appendix on page 33. The comprehensive set of historical data is compiled from information available from public sources such as Eurostat, ENTSO-E and IEA. The model is calibrated based on historical electricity prices, emissions, and volumes of generated and exchanged electricity.

The European power market scenarios are based on the study “EU Energy, Transport and GHG Emissions Trends to 2050” published by the European Commission in 2016. It shows a trend path to 2050 adapted to the countries of the European Union, while taking into account the specific initial conditions of every country in the EU 28. Moreover, recently published national plans are used to react to adapted national planning and new market developments. This applies to France, United Kingdom and Germany, some of the most important electricity markets in Europe.

The commodity prices in the scenarios are taken from the “World Energy Outlook 2016” of the International Energy Agency. The scenario “450 ppm” is applied to reflect the Paris climate conference decisions in 2015. It predicts a steep increase in CO_2-prices and a slight rise in fuel prices until 2040.

Figure 11 visualises the electricity system’s requirements for the ability of thermal power plants (lignite, hard coal, gas, oil and nuclear power plants) to vary in their level of power generation according to the market simulation. The vertical axis is relative to the maximum power generation of those power plants, so that the values of different countries become comparable to each other. A value of zero percent marks a situation where no load change is necessary from one hour to another. No flexibility is needed in such situations. A value of 25 percent indicates that 25 percent of the maximum thermal power generation capacity needs to ramp up within one hour, for Germany this translates into about 12.5 GW. A negative value indicates ramping down. Every square represents a certain range of those load gradients. If the square is dark blue, the specific magnitude of load gradients occurs often. A light blue indicates a load gradient that occurs seldom but nevertheless needs to be ramped up/down for the sake of security of supply. The blue line indicates the gradient, above or under which 100 extreme gradients occur in the specific year, so the red area marks all gradients, which may be called extreme load gradient in the respective year. Thus, for all countries there is an increase of extreme gradients. Gradients that may be called extreme today, like the single occurrence of a high load gradient in 2015 in

Germany during the solar eclipse, will become a common situation in all regarded European markets by 2030. The precise number of occurrences of load gradients in GW per hour can be seen in the appendix, Figure 18.

It becomes evident that the usage of flexible power plants is more common in Denmark than in the other examined countries. The demand for flexibility is high today already and the model utilized also indicates that the occurrence of extreme gradients will become more frequent. Even though the need for flexible power plants remains on a lower level in the other four countries, the behaviour and the need for more flexibility is apparent. If the share of wind and solar increases even further in the far future, the picture for the four bigger electricity markets could develop into a similar direction as the one for Denmark: In some hours nearly the entire thermal power plant capacity starts up or shuts down. Figure 11 shows hourly load gradients only, but high gradients may occur in a row (sun fall and wind peaks), leading to even more intense ramping up than shown in Figure 10.

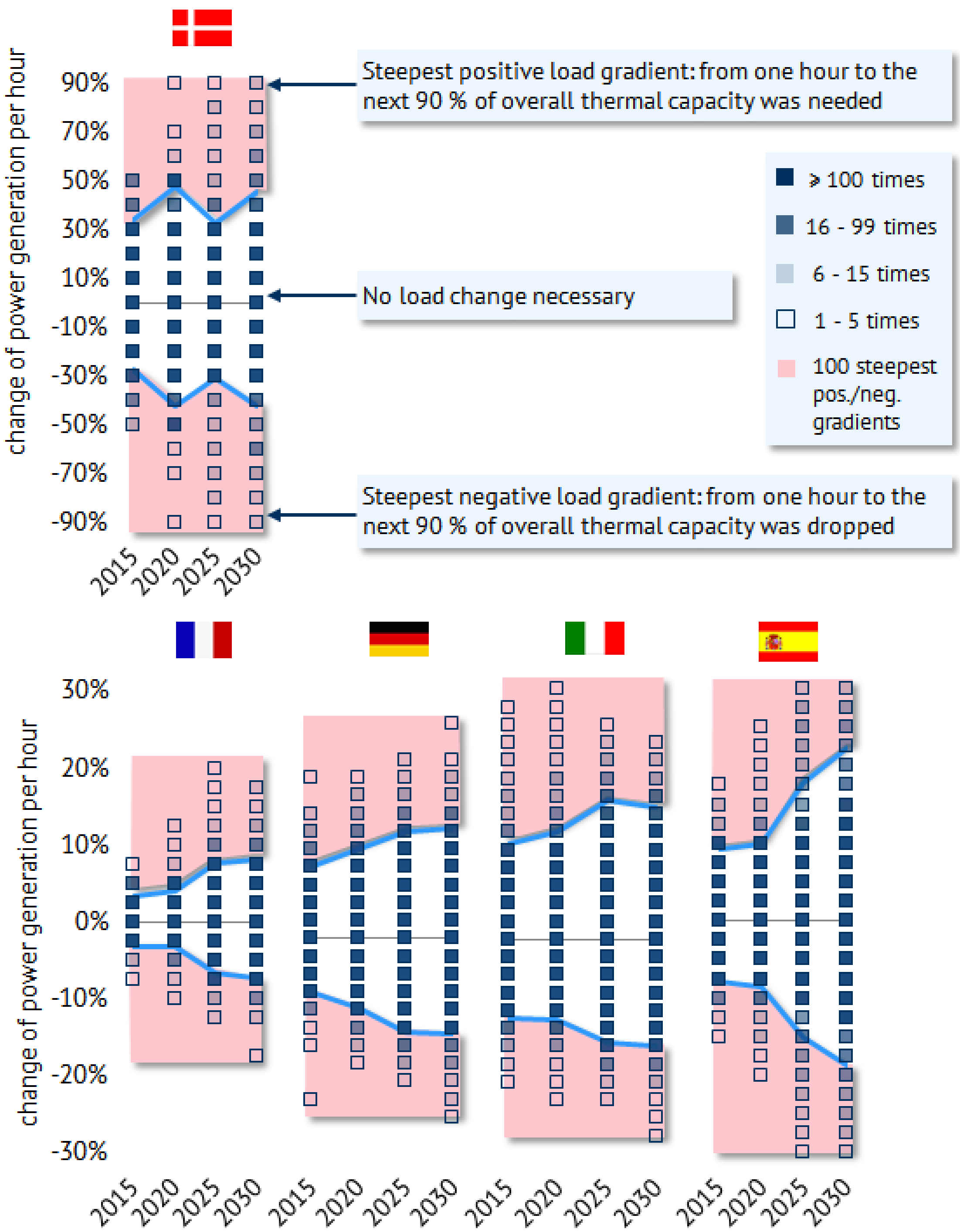


Figure 11: Development of the change in use of thermal power generation in different countries in % of maximum power generation per year

The change of power generation to the positive direction is not completely symmetric to the negative direction, very obvious for Italy in 2015 and 2020. A reason for this is the different time-lag of sun rise/fall and increasing/decreasing power demand in the morning and in the evening. Increasing demand goes along with increasing solar feed-in.

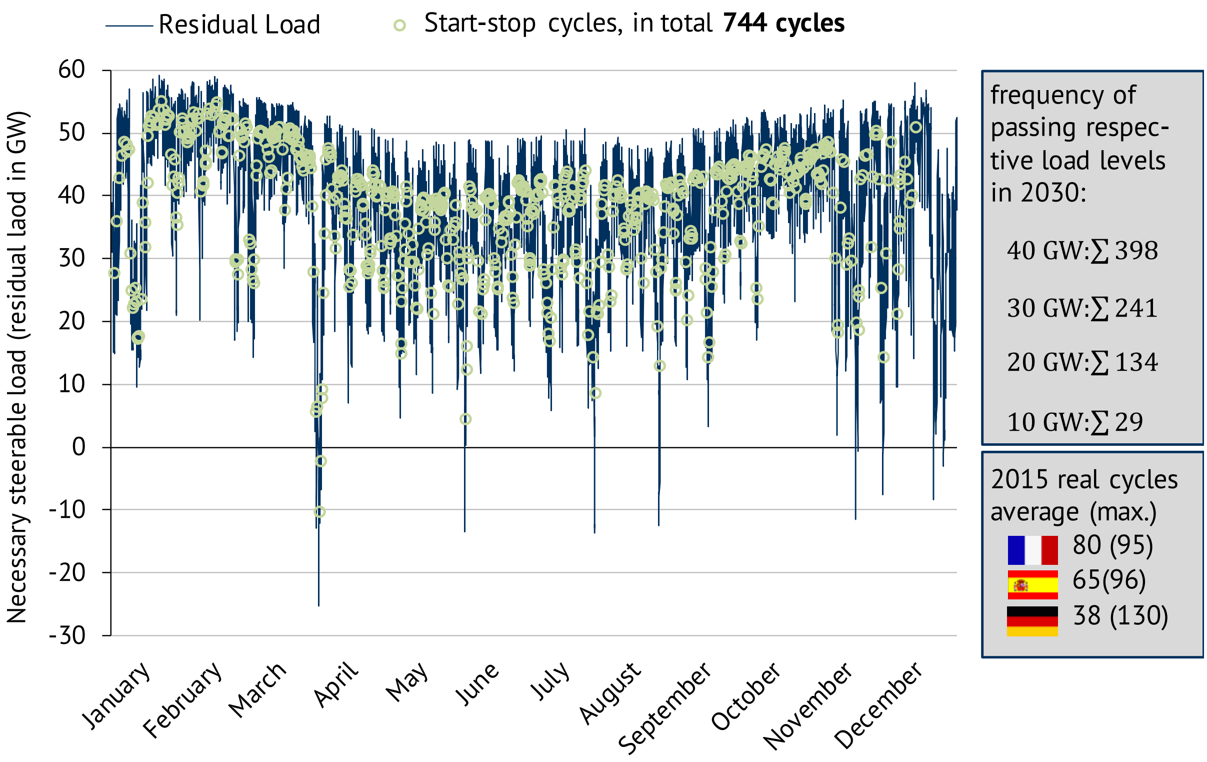


Figure 12: Hourly necessary steerable load in 2030 and start-stop cycles in comparison to real cycles in 2015

The number of start-stop cycles of power plants supplying daily peaks is depicted in Figure 12. A start-stop cycle means shutting a power plant down when its power generation is not needed and starting it up again as soon as the demand returns. The residual load as the y-axis is defined as the necessary steerable load in Germany in every hour of 2030, according to the simulation. All existing and planned storages and import/export capacities have been considered in this simulation, thus this residual load has to be supplied by flexible generation or other surplus flexibility options. It shows values of up to 60 GW and down to -25 GW. A hypothetical power plant with a capacity of up to 10 GW needs to cycle 29 times a year according to the residual load. At a capacity of 40 GW a power plant needs to cycle 398 times a year. Those power plants generating daily peaks may look at the daily average residual load and generate the respective peaks of each day. Following this idea, 744 cycles per year occur in 2030. In reality there are more factors for cycling or not cycling of power plants, such as heat demand, supply of balancing energy or price signals in the intraday market.

In 2015 gas-fired power plants performed 80 cycles in France, 65 cycles in Spain and 38 in Germany. These are averaged values for the power plants, which are part of the analysis Figure 8. There is an increasing demand for start-stop cycles, today’s power plants do not perform that amount of cycles. In the future power system inflexible power plants will be forced to keep on running with minimum load, with lower efficiency and higher emissions for the sake of preventing cycles. This must-run load is a barrier for the integration of vRES. In the future, reducing must-run by replacing inflexible power plants with more flexible gas engines and gas turbines may facilitate the integration of vRES into the electricity system by providing more flexibility.

4 POLICY RECOMMENDATIONS

Especially in light of the European Commission's proposal to redesign the EU electricity markets, increased flexibility will play a pivotal role. First legislative proposals for the redesign have been expressed in the winter package 2016. In the following paragraphs, important points for flexibility options are summed up.

- Flexibility is becoming a crucial system parameter for all market actors: steerable power plants, demand, energy storages, heating and mobility applications need to provide different types of flexibility. There is no flexibility option offering all the flexibility needs efficiently, it is a mix of different options which performs best. Simultaneously, all flexibility sources complement each other and compete with each other.
  Today it is not clear which mix this will be, a level-playing field is necessary to find the optimum. For consumers, storages, power plants and sector coupling applications (mobility, heating) price-constitution (market rules), price-components (regulator) and environmental policies should promote competition between all flexibility options.
- Theoretically, flexible capacities of power plants, demand, storages and other flexibility options can contribute their individual strenghts to both, energy only markets and capacity markets. However, in actually implemented capacity mechanisms, static base load demand and base load electricity generation is being repaid, although the system does not need neither of the two. Because the respective market design must repay quickly available flexible capacity, liberalized and liquid short-term energy-only markets are the best option to repay only those technologies, which are able to follow the price signal. So, all flexible technologies can be used for different situations and complement each other in order to establish a reliable and efficient energy system of the future.
- Efficiency is of utmost importance, but the electrical efficiency of power plants at full load is not the key parameter. Contribution to must-run, low possibility of start-stop cycles, high efficiency drops at minimum load operation, high fixed cost and environmental aspects arising from life cycle asessement need to be considered, too. Efficiency in supplying flexibility is the important goal.

APPENDIX

MODEL DESCRIPTION

The energy market model Power2Sim was applied to calculate the scenarios. Power2Sim is a fundamental software program produced by Energy Brainpool to simulate the development of electricity prices. It is based on a simulated merit order curve, by means of which the hourly wholesale electricity prices for all European countries are precisely calculated.

The short-term marginal costs of power plant electricity generation, the available generating capacity, and demand are the three main factors that determine the price of electricity. Power2Sim distinguishes between conventional and renewable power generation facilities. Electricity generation from renewables is taken into account before various conventional power plants, based on their short-term marginal costs, are included in the merit order model. The electricity generated from renewables is deducted from overall demand. Conventional power plants must therefore generate the remaining amount of electricity (residual load). In the model, renewable energies are taken into account differently, depending on the type of technology. Historical load data always serves as a basis to map the existing generation systems as precisely as possible. Power2Sim lists Europe's entire conventional power plant fleet and includes individual specifications such as fuel, efficiency and availability. This information is used to compute the merit order price.

The load model forecasts electricity demand in each country down to the hour based on specific day profiles, holiday and school holiday calendars as well as scenario trends.

The import and export model allows cross-border flows to be calculated for each border based on the cross border capacity. By including cross-border flows in the system, electricity prices in connected European electricity transmission grids can be calculated much more precisely.

All Power2Sim sub-models and their interaction are visualized in Figure 13.

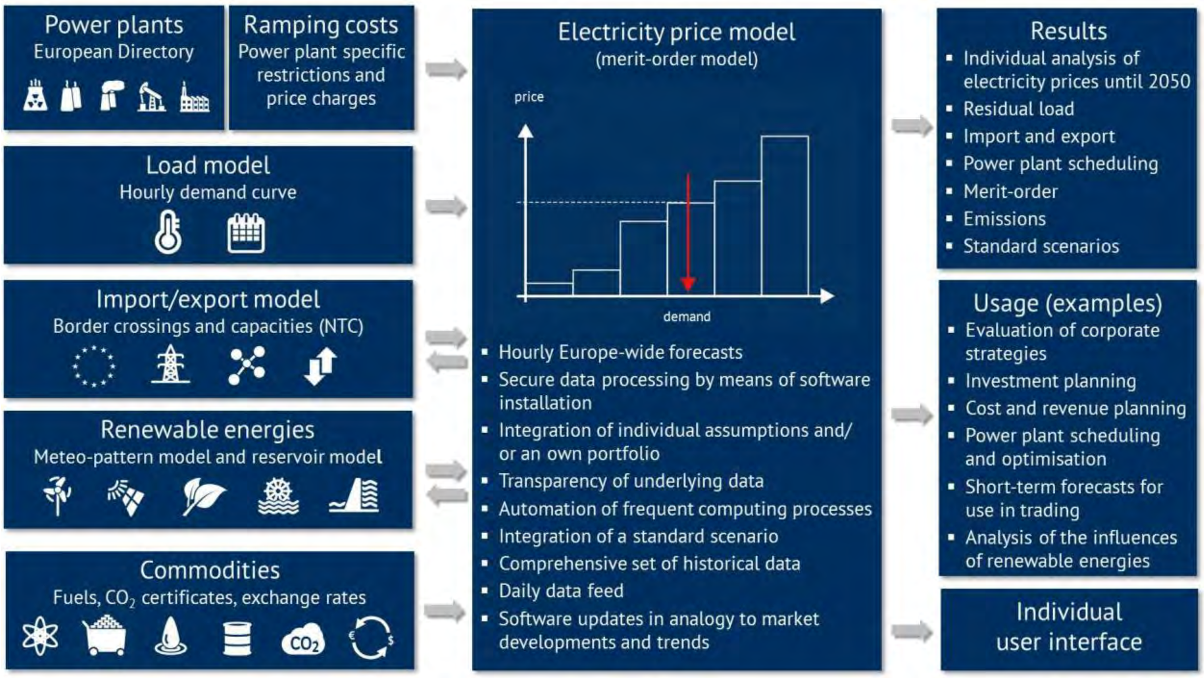


Figure 13: Structure of Power2Sim

The comprehensive set of historical data is compiled from information available from public sources such as Eurostat, ENTSO-E and IEA. The model is calibrated based on historical electricity prices, emissions, and volumes of generated and exchanged electricity.

The European power market scenarios are based on the study “EU Energy, Transport and GHG Emissions Trends to 2050” published by the European Commission in 2016. It shows a trend path to 2050 adapted to the country and to the European Union taking into account the specific initial conditions of every country in the EU 28. Moreover national plans published recently are used to react to adapted national planning and new market developments. This applies for France, United Kingdom and Germany.

The commodity prices in the scenarios are taken from the “World Energy Outlook 2016” of the International Energy Agency. The scenario “450 ppm” is applied to reflect the Paris climate conference decisions in 2015. It predicts a steep increase in CO_2-prices and a slight rise in fuel prices until 2040.

FURTHER FIGURES AND TABLES

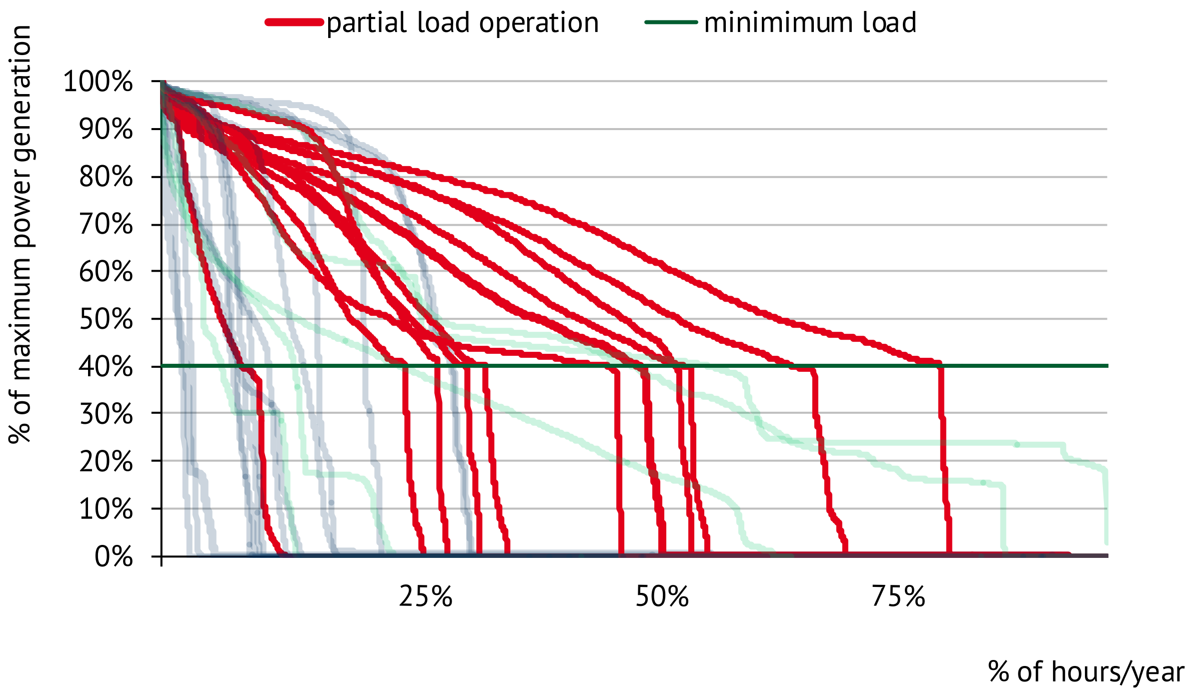


Figure 14: Sorted annual load curves of 12 gas-fired power plants in the “partial load operation mode” in France, Germany and Spain (Source: EEX, Entsoe)

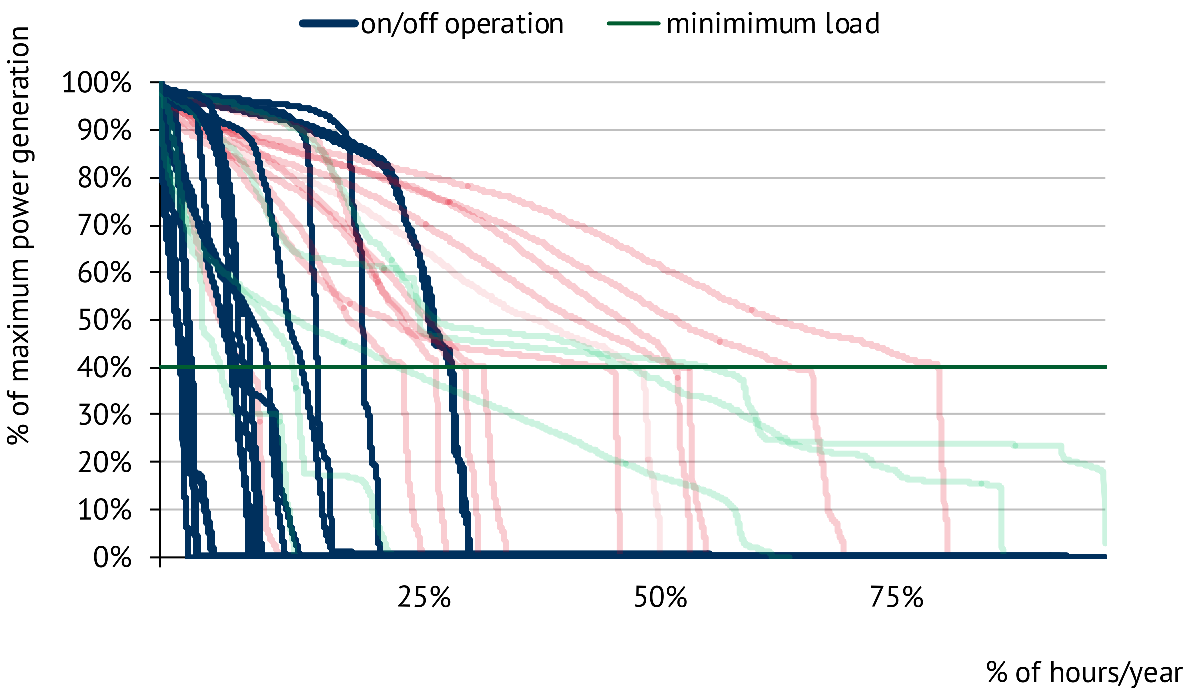


Figure 15: Sorted annual load curves of 11 gas-fired power plants in the “on/off operation mode” in France, Germany and Spain (Source: EEX, Entsoe)

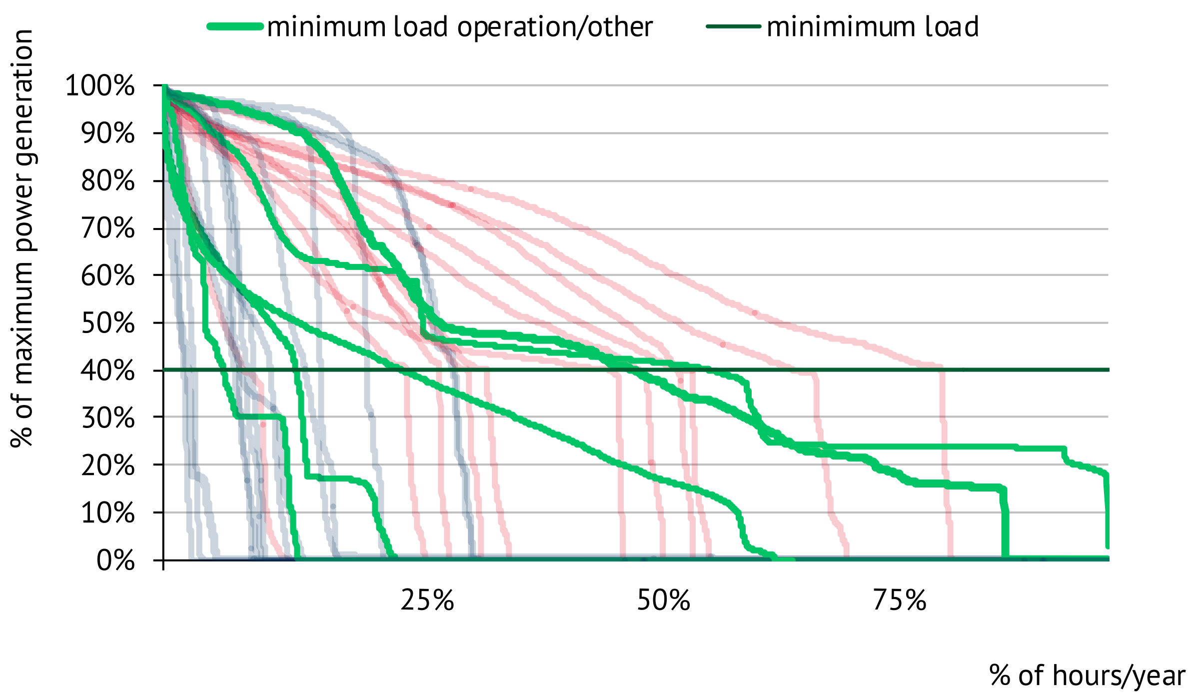


Figure 16: Sorted annual load curves of 9 gas-fired power plants in the “minimum load operation mode/other modes” in France, Germany and Spain (Source: EEX, Entsoe)

The figures 14-16 show sorted annual load curves of in total 30 gas-fired power plants in Germany, France and Spain. The power plants are classified into three different types of operation, partial load (Figure 14), on/off operation (Figure 15) and minimum load operation/other according to their generation behaviour.

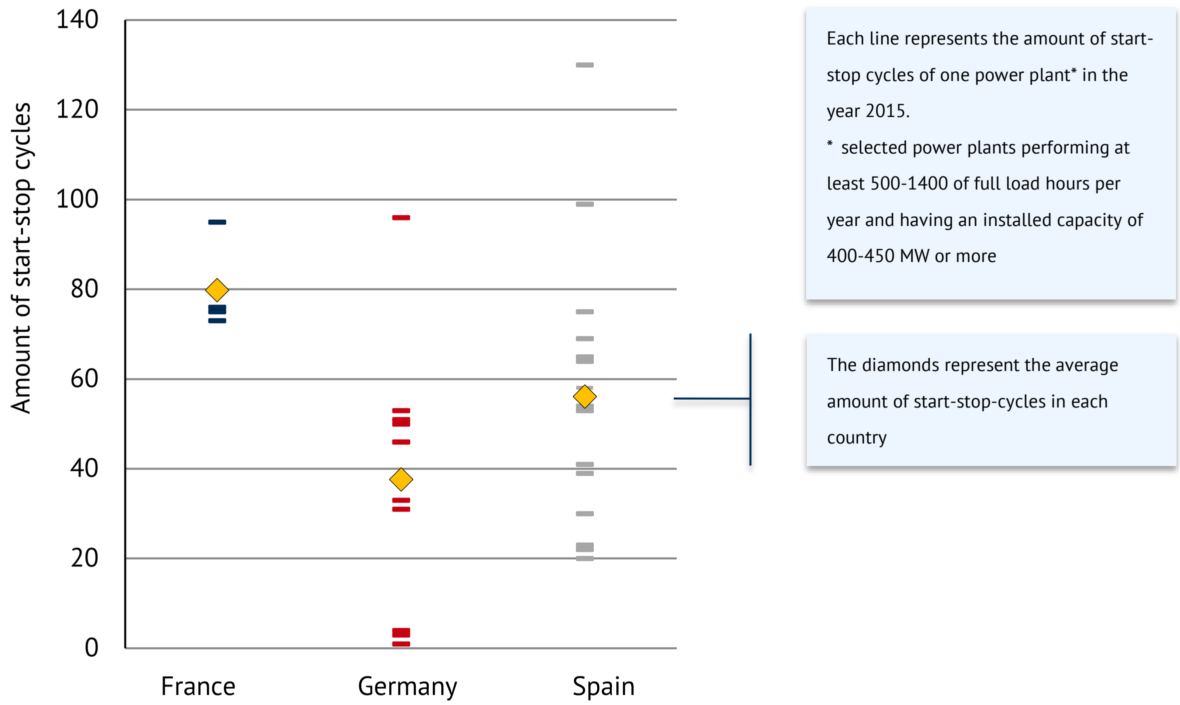


Figure 17: Amount and average of start-stop cycles of gas-fired power plants per year in different countries (source: EEX, Entsoe)

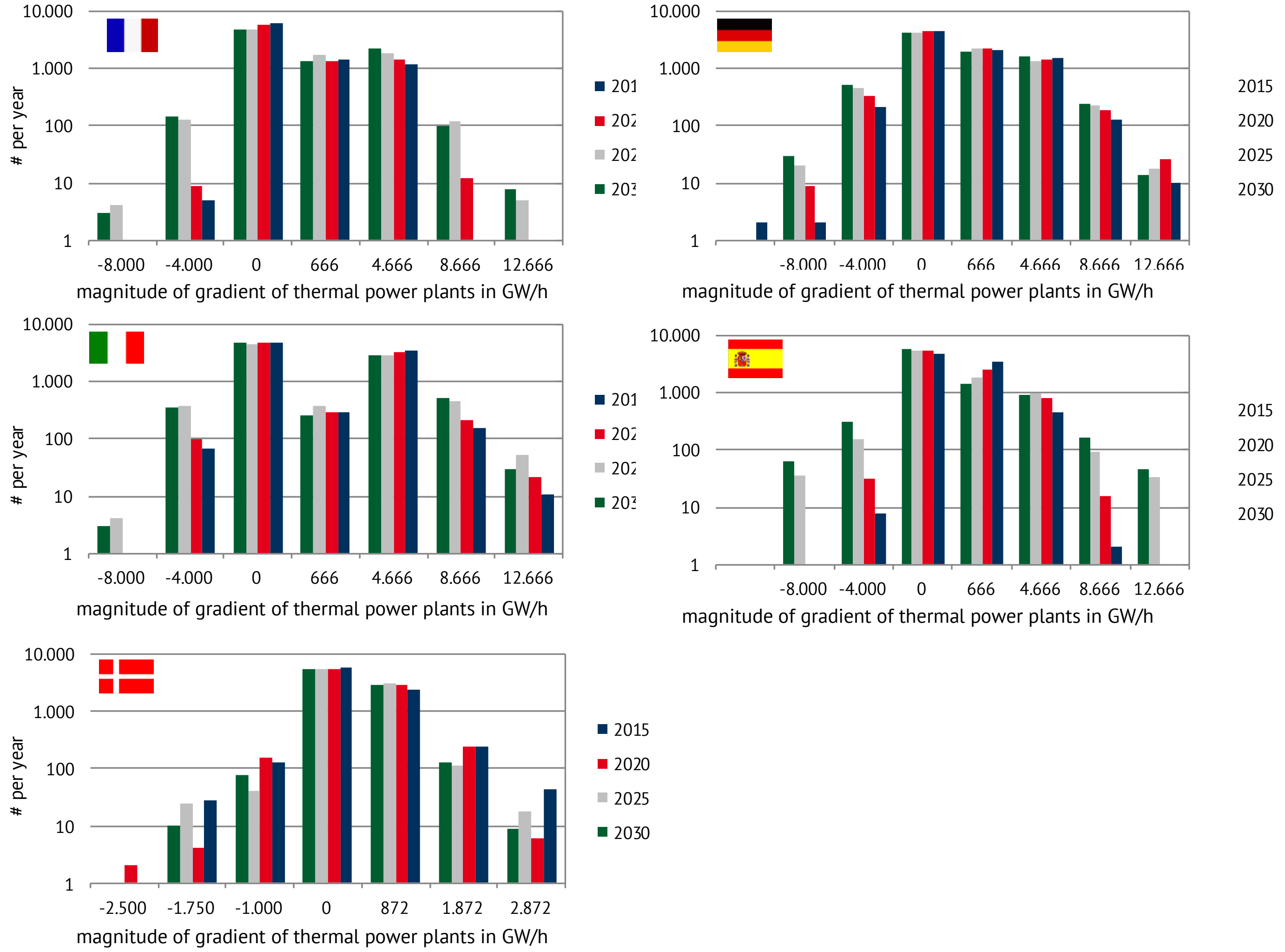


Figure 18: Occurrences of load gradients in the respective country and year.

Figure 18 visualises the frequency and the scale of changes in power generation by thermal power plants in different countries and years.

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Engine power plants

EUGINE questionnaire among the members.

EFFICIENCY DROP AT MINIMUM LOAD

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Engine power plants

EUGINE questionnaire among the members.

ABOUT ENERGY BRAINPOOL

Energy Brainpool is the independent market specialist for the energy sector, with a focus on the electricity and energy trade in Europe. Our expertise includes analysis, forecasting and modelling of energy markets and prices, scientific and practice-oriented studies, individual consulting as well as training for the energy sector.

For more than ten years, we have been combining in substantial knowledge and competence with practical experience in the area of controllable and fluctuating power.

PHILOSOPHY

Neutrality, independence, reliability and a comprehensive understanding of the energy sector and energy markets – these are the basics for implementing optimal solutions to the challenges you face in a changing market. As a competent partner, Energy Brainpool offers combined services to handle all issues of the energy trade under one roof.

Energy Brainpool's aim is to combine our expertise in the fields of analysis, consultancy and training in individual solutions to set the course for your future business success.

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- Enhancing efficiency by optimising current business models and implementing new once
- Ensuring planning security in the implementation of your projects
- Increasing revenue and reducing risks
- Entry and positioning within a changing market

INDIVIDUAL PRODUCTS AND SERVICES

With our comprehensive service concept, we are able to support our customers in the fields of policy, finance, strategy and organisation. We accompany our customers throughout all phases of the solution process – from scientific analysis, individual consulting and development of the ideal strategy and required tools to practical realisation as well as staff and management training.

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