MEMORANDUM

Dynamic distribution grid fees

An economic perspective on the system of grid fees in Germany

This is a machine translated version of a study originally published in German. The original is available at neon.energy/variable-netzentgelte.

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On behalf of LichtBlick SE

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Neon Neue Energieökonomik is an energy industry consultancy based in Berlin. As a boutique, we have specialised in sophisticated quantitative and economic-theoretical analyses of the electricity market since 2014. With consulting projects, studies and training courses, we support decision-makers with the current challenges and future issues of the energy transition. Our clients include governments, regulatory authorities, grid operators, energy suppliers and electricity traders from Germany and Europe.

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1 Introduction

Energy transition. The decarbonization of the energy system means, on the one hand, the conversion of electricity generation to primarily wind and solar and, on the other hand, the extensive electrification of the space heating (primarily through heat pumps), transport (primarily through battery electric vehicles) and industrial sectors. This means a massive increase in annual electricity consumption. If households are not incentivized accordingly, this also means a massive increase in peak load, because people will then heat their homes and charge their vehicles when it is convenient or just happens to be convenient. The consequences would be high costs for the provision of electricity through large-scale storage and hydrogen as well as massive expansion of the transmission and distribution grids.

Flexibility. However, many of the new consumption devices have an inherent flexibility: heat pumps due to the thermal inertia of buildings or water heat storage systems, electric vehicles due to batteries. In principle, it is often technically possible to shift the load by a few hours or (in the case of cars) days without incurring significant costs or sacrificing comfort. However, this requires financial incentives, which are currently lacking across the board. Decentralized flexibility, i.e. appliances that are connected to the low voltage and operated by private households or small businesses, plays a key role here due to their sheer mass.

Large volume. Today, the cumulative connected and charging capacity of heat pumps, electric cars and home storage systems in the low-voltage grid is around 20 GW, which corresponds to around 25% of the installed capacity of flexible power plants. The German government expects this ratio to be reversed as early as 2030: with 250 MW of decentralized flexibility, decentralized flexibility will increase to around 350% of flexible power plant capacity. For 2045, the BMWK long-term scenarios then expect a further increase to 630% of power plant capacity. The cumulative capacity of decentralized flexibility not only exceeds the available power plant capacity many times over, it also exceeds the installed capacity of large-scale flexibility options such as electrolysers, large batteries and power-to-heat plants in district heating grids (Figure 1).

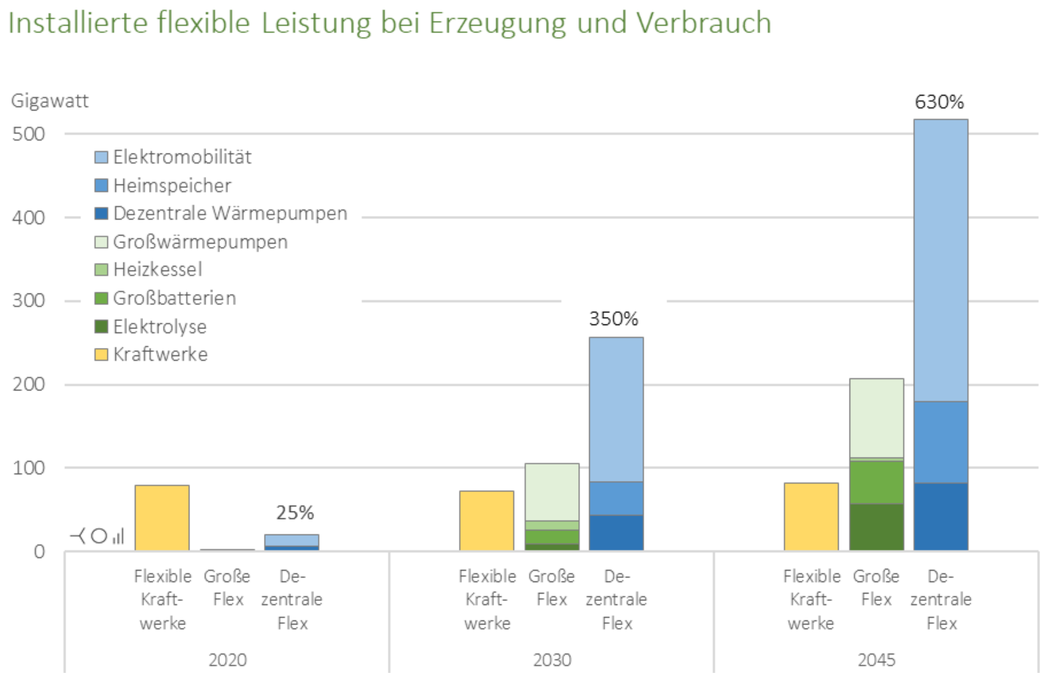

Figure 1. Installed capacity of various potentially flexible technologies today and in the future. Decentralized flexibility refers to low-voltage connections. Own illustration based on the BMWK long-term scenario "T45 electricity" (2022); the electromobility connection capacity was calculated as 11 kW for 75% of the passenger cars; the capacity of large batteries and home storage systems is based on the corresponding information in the Electricity Network Development Plan 2037 / 2045 (2023) and was calculated for the year 2030 by linear interpolation between the information for 2020 and 2037.

System-friendly operation. A central challenge of the energy transition is to encourage heat pumps, electric cars and home storage systems to preferably draw electricity when the wind is blowing or the sun is shining and the grids have sufficient free capacity. The availability of renewable energies is generally well reflected in the electricity price; the price falls when availability is high. It is therefore sufficient if consumers are exposed to real-time prices. Grid utilization, on the other hand, is not reflected in the zonal German electricity market. In principle, grid-supporting signals in the distribution grid with an effect on system utilization can be implemented using four mechanisms: A local electricity market, a local flexibility market, intervention rights for grid operators and administrative price signals such as grid charges.

Local electricity market. In a highly granular electricity market, prices at each distribution grid connection point are determined by supply and demand as well as grid capacity as an equilibrium price (distribution grid nodal pricing). For many reasons, this does not appear to be a realistic option in the distribution grid for the coming decades, even if it were to be used in the European transmission grid.

Flexibility market. In principle, local flexibility markets work like nodal pricing in the distribution grid. However, they do not replace the zonal wholesale market, but are set up in addition and parallel to it. However, the parallelism of the two markets incentivizes strategic bids in order to benefit from price differences. Such bidding strategies are referred to as inc-dec gaming (see box). Such inc-dec gaming is problematic for various reasons. It is inherent to the fundamental market structure and is difficult to regulate, which is why we do not consider local flexibility markets to be a sensible option.

Box: Inc-dec gaming in markets for redispatch and local flexibility

Call-based redispatch markets. A call-based redispatch market is characterized by the fact that participation is voluntary for market players and compensation is paid for the call and on the basis of bids from these same market players. Such call-based redispatch markets have been considered problematic in previous studies, as they can lead to strategic bidding behavior (Hirth & Schlecht 2020).

In regions of scarcity. Essentially, a call-off-based redispatch market creates problematic incentives for generation plants and consumers that exacerbate congestion. The incentives are illustrated below using the example of generation plants. Generators in regions of scarcity anticipate that (higher) profits can be generated by marketing their generation on the redispatch market. They therefore bid at higher prices on the electricity market and thus price themselves out of the zonal market in order to be available for the downstream redispatch market. These strategies can be understood as an optimization between two markets.

In surplus regions. Conversely, generators in surplus regions anticipate profits by downregulating on the redispatch market. To make this possible, they submit low bids below their marginal costs on the electricity market and thus force themselves onto the market. They can bid at this price as they can free themselves from their supply obligations at even lower prices on the redispatch market that takes place later. In principle, they therefore buy back the electricity that was previously sold at a high price on the electricity market at a lower price later on.

consumers. The same incentives shown for producers in the example above exist for consumers in a mirror image, but with the same congestion-increasing effect. In shortage regions, they buy cheaply on the electricity market and sell on the redispatch market. In surplus regions, they withdraw from the electricity market so that they can then buy cheaply on the redispatch market.

Consequences. This strategic behavior of market participants on both sides of the bottleneck leads to an exacerbation of bottlenecks, windfall profits, problems for financial hedging transactions, false investment incentives and harbors operational risks.

curtailment. Intervention rights for grid operators can, for example, take the form of curtailment or power throttling, as has been intensively discussed in Germany for years in the context of Section 14a EnWG. Such intervention rights are desirable and useful in an emergency in order to prevent system disruptions, frequency drops or the downtime of entire distribution grids. However, as an everyday instrument for load-side flexibility, they have a number of disadvantages. In particular, there is no possibility of weighing up the costs and benefits of providing flexibility in the event of a call-off, because at least the call-off is not voluntary. The strong role of grid operators is also likely to hinder the development of innovative business models and products. They can also hinder the provision of market flexibility, such as the provision of balancing power or scheduling products. Last but not least, they are also a communication hurdle for the acceptance of heat pumps and electric vehicles, as the heated debate in the press shows.

Administrative prices. Administrative price signals are those that do not result directly from the local, momentary balance of supply and demand, but are determined ex ante by a central actor. As a rule, such proxy prices originate from a spatial and/or temporal differentiation of grid charges, i.e. they are parameterized by grid operators. It is in the nature of things that prices are only approximated because they are not formed on the basis of the current system status from bids and grid congestion. For example, time-of-use grid charges usually only differ within a few time steps, which are also set well in advance and apply to the entire distribution grid. They are therefore more or less rough approximations of "true" prices in terms of temporal and spatial resolution and lead time. Variable grid charges can therefore not always prevent overloading of grid elements. They only make overloading less likely by tending to reduce electricity consumption at times of high load. However, such a stochastic approach has always been the basis of grid design.

Assessment. Local electricity markets in the distribution grid do not appear to be feasible for the next decades and local flexibility markets have inherent inc-dec incentives. As a result, we consider a combination of administrative price signals in the form of variable grid charges (as a rule) and intervention rights for grid operators (in an emergency) to be the preferred approach for operating decentralized flexibility in a grid-friendly manner and preventing grid overloads.

Structure. With this memorandum, we want to contribute to the further development of the grid fee system in Germany. To this end, we describe in Section 2 what optimal grid-friendly price signals look like in theory. In Section 3, we analyze the current grid charge system in terms of its incentive effect and show that there are already de facto time-variable grid charges in Germany due to the capacity charge. However, these do not help to relieve the distribution grids. In section 4, we therefore describe how explicit time-variable grid charges can be used to incentivize the grid. We conclude with an outlook on possible next steps.

2 Optimal grid-friendly price signals in theory

Thought experiment. When discussing specific proposals for the further development of grid charges, it is helpful to first think through what theoretically optimal grid-friendly electricity prices would look like. Even if these theoretical price signals remain unattainable in practice for good reasons, they provide a useful benchmark for evaluating specific proposals.

Complete electricity market. In a hypothetical complete electricity market, the preferences and willingness to pay of all consumers as well as the cost structure and limited availability of generation plants and storage facilities as well as the transmission and distribution grids are aggregated *in a price signal.* The price of electricity is therefore not only formed on the basis of the variable costs of power plants in a zonal electricity market (as illustrated in the merit order model), but also takes into account the scarcity of the grids. Apart from the start-up and shutdown costs of power plants, all costs can be mapped in a price per energy (€/MWh), in particular the investment costs in generation plants and grids. There is therefore no separate capacity charge or capacity payments.

System cost minimization. If this price signal can arise without market failure - i.e. without market power, transaction costs, externalities, distorting taxes and state influence on prices - then market players make economically efficient decisions: the use of power plants, the charging of electric cars, the choice of location for generation plants, the operation of storage facilities, etc. are all made in such a way that the costs of the overall system are minimized, including grid costs.

Granular prices. As electricity can only be stored and transported to a limited extent and at a cost, such a hypothetical price changes over time (e.g. every minute) and differs at each location (e.g. each grid connection point). Mathematically, such a price can be determined by calculating the increase in system costs through the marginal increase in electricity consumption at a location at a point in time (Schweppe et al., 1988). This theoretical optimal electricity price is then different at each grid connection point in the distribution grid. In times of underutilized grids, the local price differences are small and merely reflect grid losses. However, in times of fully utilized grids, local price differences are large because they reflect the current scarcity of the grid resource and the different effects on bottlenecks between the grid connection points. While a withdrawal at one location can relieve congestion, a withdrawal at another location can exacerbate congestion and necessitate correspondingly more expensive generation elsewhere.

Real electricity market. Every real electricity market is incomplete, i.e. it only reflects part of the costs and scarcities in the price. There are good reasons for this, such as the avoidance of excessive transaction costs of a highly granular price signal or politically desirable distribution effects. A complete electricity market will therefore always remain a hypothetical, theoretical consideration. However, the aim of electricity market design should be to come closer to this ideal, taking into account the associated costs. A good electricity market design in this sense is therefore one that creates incentives for plant operation and investment that are close to the economic optimum. This is an electricity market in which prices are meaningful because they reflect real costs and scarcities.

Distribution grid fees. This also applies to the design of distribution grid charges. Taking into account the wider electricity market design, limited information on the current grid status and the requirements to cover grid costs, grid charges should, from this perspective, help to approximate the theoretically optimal local electricity prices. Grid charges should therefore create incentives that complement the wider electricity market in a meaningful way and translate the scarcities of the grids into a reasonable local price signal.

3 Incentives from grid fees in the status quo

Objectives of the grid fees. The grid fees in Germany were not developed with the aim of incentivizing consumers to use the grid. Rather, they are based on the guiding principle of distributing the costs of the grid among grid users in a way that is perceived as fair. However, we recommend that grid charges be understood more from an incentive perspective, as we believe that grid charges play a decisive role in the grid-friendly operation of decentralized flexibility. In this section, we first describe how grid charges are currently calculated in Germany and then analyze the resulting incentives.

3.1 Structure of grid charges today

Types. German grid operators charge grid fees for the initial connection and then for the ongoing use of grids. We will focus here on grid utilization fees, which in Germany are only charged for electricity consumption, while in some European countries generation plants are also charged.

TSO vs. DSO. Grid charges are levied by the four German transmission system operators as well as by the approximately 900 distribution system operators. Grid fees cascade from high to lower voltage levels: downstream grid operators pay grid fees to upstream grids of higher voltage. This reflects the logic of traditional electricity systems in which generated electricity is first transformed up to extra-high voltage and then gradually -transformed down to high-, medium -and low voltage. As a result, the lower the connection voltage, the higher the grid fees. While transmission grid fees are rolled up nationwide, this is not the case for distribution grids. The costs of the local distribution grid are borne by the local electricity consumers, even if these were caused by grid expansion for generation, for example.

Basis. Depending on the type of consumption, charges are levied on three different bases in Germany: on the annual electricity consumption (energy charge in ct/kWh), on the individual peak load per quarter of an hour per year (capacity charge in €/kW per year) and a flat-rate payment independent of behavior (basic charge in € per year). The capacity charge is based on the actual peak demand and not on the connected load. The structure of the grid fees differs between large consumers from 100 MWh annual consumption with hourly measured and recorded consumption (RLM) and small customers, who are usually billed according to a standard load profile (SLP).

SLP. SLP customers normally pay a basic price and an energy charge that is multiplied by the annual electricity consumption. This also applies to customers with an intelligent metering system ("smart meter") who are not billed according to SLP but according to meter reading. Section 14a EnWG provides for reduced grid fees for heat pumps, private electric car charging points and other controllable consumption devices. The "control" can take place through economic incentives such as time-variable grid charges, via the grid connection power or through the actual control of individual devices. The Federal Network Agency is currently laying down specifications for this.

Table 1. Grid charges for SLP customers using the example of Stromnetz Berlin (gross, rounded)

Remuneration	Height
Base price	40 € per year
energy charge	9 ct/kWh

RLM. In addition to a behavior-independent fixed price for metering point operation and an energy charge, RLM customers also pay a capacity charge. The capacity charge is multiplied by the maximum quarter-hourly consumption per year, in exceptional cases also per month. Energy charges and energy charges differ in terms of hours of use (annual hours of use). This figure is calculated as a quotient of annual consumption and peak load. The structure of the grid charges changes from 2500 hours of use: with fewer hours of use, the energy charge tends to be high and the capacity charge tends to be low; with more than 2500 hours of use, it is the other way round. Table 2 shows this as an example for the Berlin electricity grid.

Table 2. Grid charges for RLM customers using the example of Stromnetz Berlin (gross, rounded)

Supply voltage	Remuneration	< 2500 hours of use	≥ 2500 hours of use
Medium voltage	Measuring point operation	393 € per year	393 € per year
	capacity charge	7 €/kW per year	71 €/kW per year
	energy charge	6 ct/kWh	3 ct/kWh
Low voltage	Measuring point operation	392 € per year	392 € per year
	capacity charge	10 €/kW per year	113 €/kW per year
	energy charge	9 ct/kWh	5 ct/kWh

RLM exemptions. §Section 19 StromNEV defines a series of exemptions and reduced grid fees, of which the discounts described in the paragraph are particularly relevant in practice. Consumers with atypical or even grid utilization receive a reduction in grid fees of up to 90%.

- Atypical grid utilization occurs when the individual annual peak load is outside defined time windows of the grid peak load, for example in summer or at night. A discount of up to 80% is then granted on the grid fees.
- Even grid utilization is deemed to exist if at least 7000 hours of use are achieved. Customers with an annual consumption of 10 GWh or more then receive a discount of up to 80%. For over 8000 hours of use, the discount even rises to 90%. Grid operators generally utilize the maximum possible fee reduction.

Relevance. These exemptions are utilized to a very significant extent. According to the Federal Network Agency's monitoring report, an individual grid fee was applied to 70 TWh of annual consumption in 2021, i.e. almost a third of industrial electricity consumption. The discount volume totaled 800 million euros, more than twice as much as five years previously. Numerous consulting firms have specialized in using combined heat and power plants and battery storage behind the metering point to raise the usage hours of large consumers above the thresholds of the exemption rules. In many companies, one of the main tasks of energy management is to optimize electricity consumption in terms of uniformity in order to benefit from the rebates.

3.2 Capacity charge as a time-variable grid fee

Capacity charges. In this section, we describe the incentives that arise from the grid charges in the status quo. Capacity charges in particular are essential in terms of their incentivizing effect on the provision of flexibility and their economic effect is often not sufficiently understood, even in technical discussions. For this reason, we analyze four aspects below:

- Capacity charges incentivize inflexible system design, which is further reinforced by the discount for even grid procurement
- Capacity charges are in fact time-variable network charges
- Capacity charges imply bizarrely high marginal costs for additional consumption in individual hours and therefore represent a barrier to the provision of flexibility
- Capacity charges are based on the individual consumption profile, while from an economic point of view it would make sense to base them on the grid load

System design. Figure 2 shows the grid charges per megawatt hour of electricity consumption using the example of the Berlin medium voltage. A flexible system design with variable electricity consumption and consequently low usage hours is shown on the left, an inflexible design for base load operation on the right. A system with 100 hours of use pays 32 times higher grid charges per megawatt hour than a system in continuous operation. The current tariff design therefore incentivizes an inflexible system design; this is further reinforced by the discounts for even grid usage.

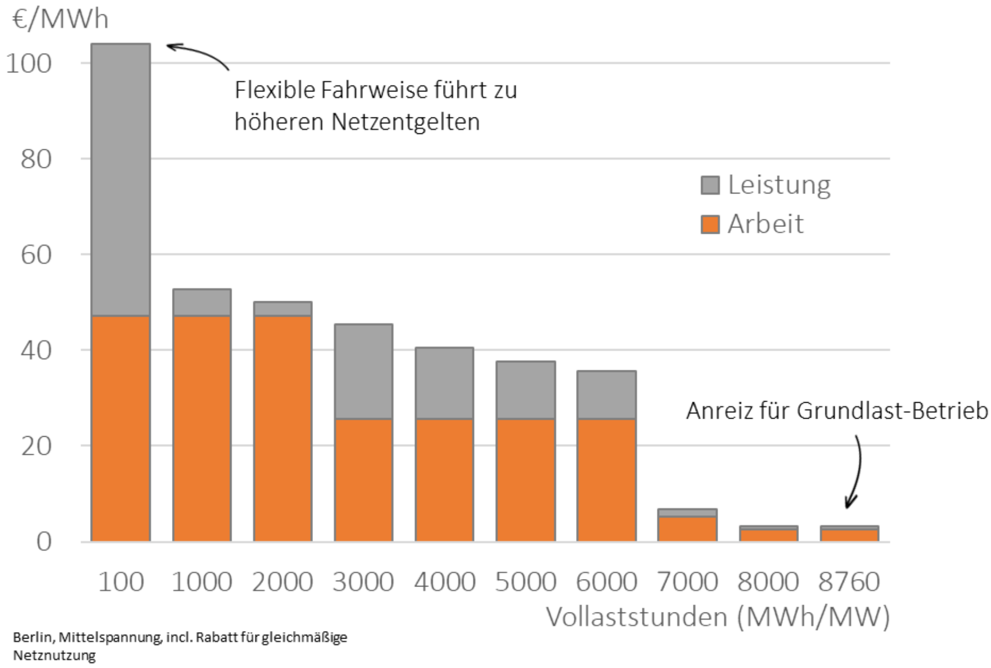

Figure 2. Grid charges for different hours of use for large customers in Berlin connected to the medium-voltage grid.

Time-variable charges. In the German discussion about time-variable grid charges, this is usually overlooked: We have had de facto time-variable grid charges in Germany for a long time with capacity charges. Capacity charges mean that the grid charges incurred for the consumption of an additional ("marginal") megawatt hour fluctuate within the year. In fact, there are two price levels: If electricity is purchased below the peak load, only the energy charge is due. If the current electricity consumption is already at the peak load, an increase in consumption also leads to a higher power payment. In other words: in these hours, the marginal grid charges due for an increase in consumption are much higher.

Example. The following example illustrates this, again using the Berlin medium voltage. Assuming that the company has the same electricity consumption every day as in Figure 3 (left). If electricity consumption increases in the morning, evening or night, only the energy charge of around €26 per megawatt hour has to be paid. However, if the daily consumption increases evenly over all hours with peak load consumption (in the example, this is 2,920 hours, daily from 9 a.m. to 5 p.m.), a higher performance payment is due. In the example, the grid fee per megawatt hour of additional consumption is then around 46 euros. So if the company increases its electricity consumption by 1 megawatt for every night hour of the year by introducing a new night shift, this will cost grid fees of €26/MWh; for a day shift, on the other hand, it would be €46/MWh. From this perspective, the company is already subject to a de facto time-of-use grid fee that fluctuates over the course of the day - except that the high-price window depends solely on the time of the *individual* peak load and is therefore unrelated to the grid load.

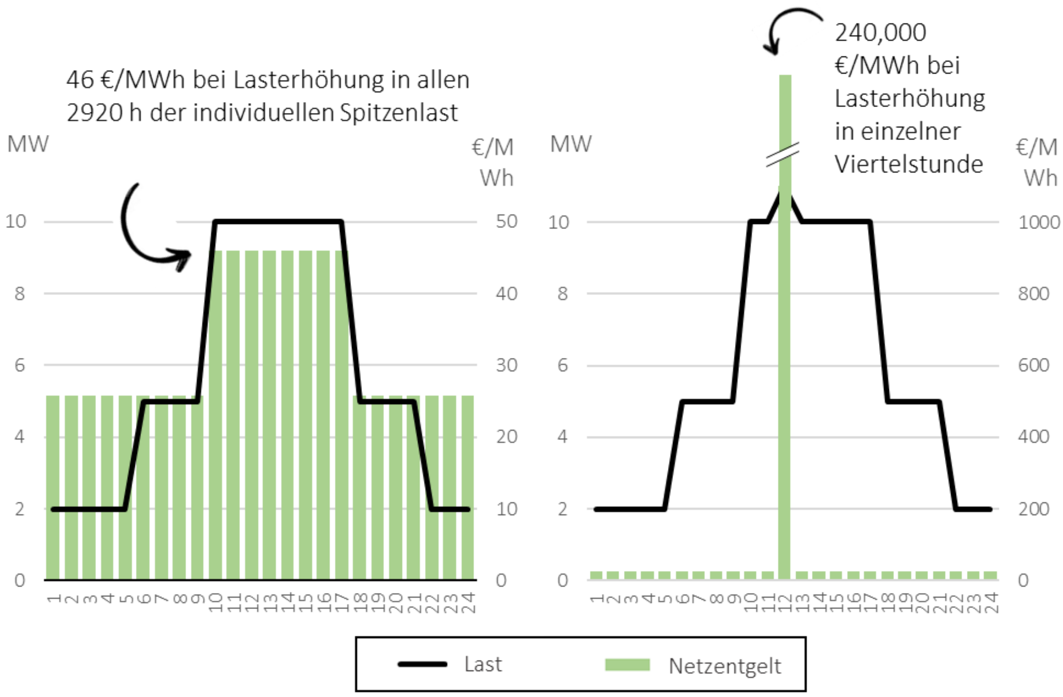

Figure 3 : Grid charges for the consumption of an additional megawatt hour over the course of the day with a load increase over the year (left) and with a load increase in a quarter of an hour (right) (example)

Flex incentives. The differences in the effective grid charges are even more bizarre if there is not a uniform increase in electricity consumption, but rather a flexibilization in the form of a short-term increase in consumption. If an additional megawatt hour is drawn from a grid connection in just a single quarter of an hour, the capacity charge for four megawatts must be paid additionally; in Berlin's medium-voltage grid, this amounts to almost €240,000 (see Figure 4, right). The effective grid charge here is therefore just under 240,000 euros per megawatt hour - that is almost ten thousand times more than has to be paid for the energy charge. Even if the additional megawatt hour consumed is spread over 100 hours, the additional costs for the additional megawatt hour still amount to 600 euros, i.e. 20 times more than the energy charge. This example shows that it is practically never worthwhile for large customers with hourly measured and recorded consumption (German: "Registrierende Leistungsmessung") to increase their electricity consumption beyond the peak output in order to behave in a system-friendly manner under the current grid charge design due to the capacity charges. Grid or market-based incentives will generally not be able to compensate for this increase in grid charges.

Individual load. The problem with the capacity charge component of the grid fees is that it is based on *individual* consumption. It is the individual peak load that defines the times at which the individual grid fee is de facto higher, because an increase in electricity consumption would lead to an additional demand charge. This also means that the resulting "high price windows" apply to all consumers at other times.

Analogy electricity market. This approach is diametrically opposed to the economic logic of prices that are formed based on the *total* demand of a market. This also applies to the wholesale market for electricity: on the electricity exchange, the equilibrium price is determined by total demand and not by individual demand. If the logic of grid fee payments were applied to the electricity exchange, all consumers would pay an individual price. The individual electricity price would always be high when a lot of electricity is consumed individually, even if a lot of wind and solar power is available at that moment. Conversely, the individual electricity price would be very low when hardly any electricity is consumed individually, even in a dramatic shortage situation.

Grid load. According to economic logic, grid fees should depend on the total grid load, i.e. the joint consumption profile of all customers and not the individual consumption profile of each customer. In a grid area, everyone should pay the same grid fees for an increase in their consumption at all times, because they all have the same effect on the limited resource of the grid.

Capacity charges as a proxy. The capacity charges based on individual peak consumption are actually intended to reflect the influence of consumption on the grid load. The maximum load contribution calculation described in the StromNEV (Annex 4 of Section 16 (2)) estimates the share of consumers in the maximum grid load. This estimate is made depending on their hours of use, because it is likely that consumers with high hours of use cause a higher share of the maximum grid load than those with fewer hours of use. Therefore, consumers with high hours of use also pay a higher capacity charge according to their approximated degree of simultaneity. In an energy system without load-side flexibility and without feeding large amounts of electricity into distribution grids, approximating degrees of simultaneity by the number of hours of use may have provided plausible results. However, in the future energy system, the load must react flexibly to electricity prices and grid loads and decentralized generation will increasingly be fed into distribution grids, so that the approximation simply delivers incorrect results.

Summary. Apparently, there are currently no time-variable grid charges in Germany. However, the capacity charge system, which is levied on the quarter-hourly annual peak load, de facto causes grid charges to be staggered over time. However, this creates false incentives in various respects:

- An inflexible design of systems and processes (electricity consumption that is as uniform as possible) is systematically encouraged. This effect of the capacity charge is further reinforced by the discount for even grid utilization.
- The actual resulting profile of individual grid charges is not directly related to the grid load. Even in an oversupplied grid, additional consumption may be heavily penalized financially.
- Capacity charges based on individual peak loads lead to bizarrely high marginal costs if electricity consumption is only increased in individual hours. This prevents industrial flexibility in the sense of utilizing electricity in the event of negative exchange prices or grid bottlenecks.

Against the backdrop of solar self-generation and grid-friendly charging of electric cars, the introduction of capacity charges for households is repeatedly discussed. We do not believe that this makes sense for the reasons described above. Instead, we recommend the introduction of explicit time-variable grid charges that have a grid-relieving effect. We describe the most important design options for this in the following section.

4 Time-variable grid charges for small consumers

Technical requirements. In order to be able to introduce time-variable grid charges for small consumers, they must be able to measure their electricity consumption with a resolution of at least a quarter of an hour. This is possible through smart metering systems or the use of meter reading measurement. Without these technical requirements, a time-variable grid fee cannot be billed. Until all consumers fulfil the necessary technical requirements, it is conceivable to offer time-variable grid charges as an optional, non-mandatory billing model.

Lead time. When designing time-variable grid charges for small consumers, the key question is when the grid charges are set. There are the static and dynamic determination approaches presented below, as well as mixed forms of these.

Static grid fees. With static time-variable grid charges, the high price windows are defined with a long lead time and for a longer period, typically one year. In the simplest case, the high and low price windows differ only in the time of day, but several price levels and/or consideration of seasons, weekdays and public holidays are also possible. This tariff structure is also known as "time-of-use" because the level of the grid charges is determined solely by the calendar date. Parameterizing the grid charges in this way on the basis of statistical findings about the grid load makes sense if a high utilization of the relevant grid elements is subject to predictable rhythms. This is often the case, for example, in grid areas that are dominated by private consumption or solar generation. In load-dominated grids, the peak load can be expected in the early evening during a weekday in winter and a second peak load can regularly be observed at midday. In grids that are also characterized by solar generation, so much electricity is generated at midday in the summer months that the grid load becomes negative, i.e. electricity is fed back into upstream grids. In most rural distribution grids in Germany, this is likely to be the case today or within a few years at the latest. Figure 4 shows an example of the grid load and suitable static time-variable grid charges for both cases.

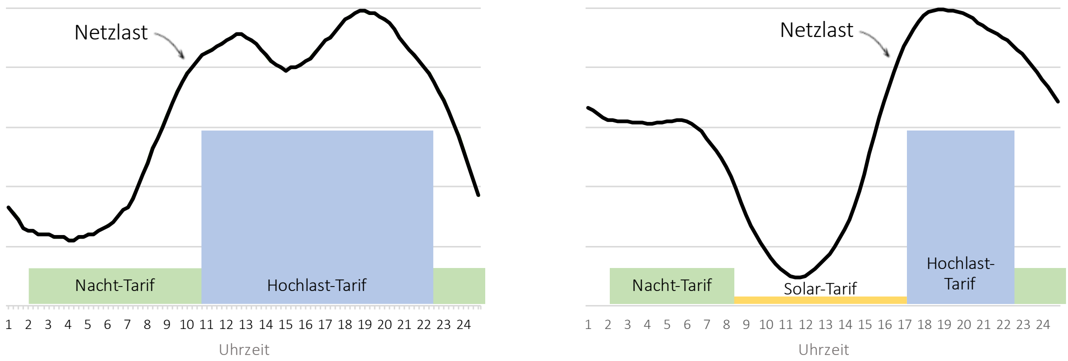

Figure 4. Illustrations of static time-variable grid charges with two tariff levels in a load-dominated grid (left) and with three tariff levels in a grid characterized by load and solar generation (right).

Dynamic grid charges. The alternative to determining static time windows in advance is to determine grid charges based on knowledge of the actual state of the system. Such a dynamic grid charge can therefore reflect the current system status much better than static grid charges (Figure 5). Dynamic grid charges are particularly useful when the grid load is difficult to describe in calendar terms, for example when grids are dominated by wind power generation or electrical heating. In the latter case, although the peak load is predictable on a winter evening, the day cannot be predicted in advance due to the strong fluctuations in outside temperature over the winter. How quickly the level of the grid fees is set has an impact on the efficiency and effectiveness of the grid fees as an incentive instrument: the more quickly they are set, the more accurately the current system status can be reflected. However, short-term lead times are costly for both grid operators and grid users. It is conceivable to make the determination a few days in advance on the basis of weather forecasts, close to real time on the basis of load flow measurements or ex-post on the basis of final grid data. An ex-post determination, such as that used in the winter trimester in the UK, ensures that the grid charges are highest in the hours with the highest grid load. However, this privatizes the forecast of the peak grid load, resulting in a high level of effort and uncertainty for small consumers.

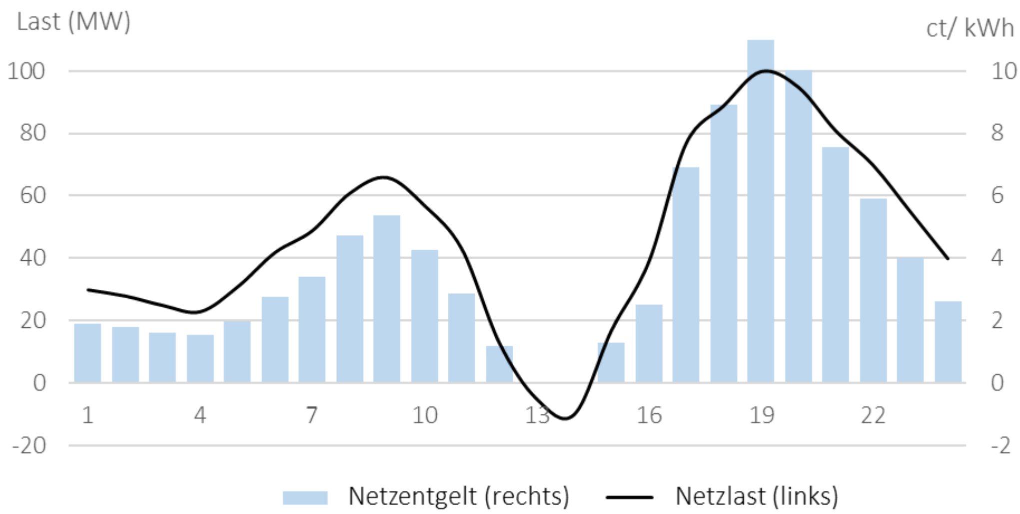

Figure 5. Illustration of a dynamic grid charge that varies depending on the measured grid load.

Critical peak pricing. Critical peak pricing (CPP) is a hybrid of static and dynamic charges. Here, long predetermined time windows of different tariff levels are combined with price incentives announced at short notice during critical hours. CPP is usually offered as a supplement to ToU tariffs for particularly flexible consumers, who receive a one-off payment or lower charges in low-load time windows.

Overview. According to ACER (2023), 21 of the 27 EU member states currently use static time-variable grid charges in the distribution grid. Around half of these also have time-variable charges at transmission grid level (Figure 6). The static time-variable grid charges are implemented in the form of two or a few price levels, as shown in Figure 7 shows. Apart from Italy, Germany is the only Western European country without explicit time-variable grid charges. In contrast, a dynamic component in the grid charges only exists in the three countries France, Norway and Sweden.

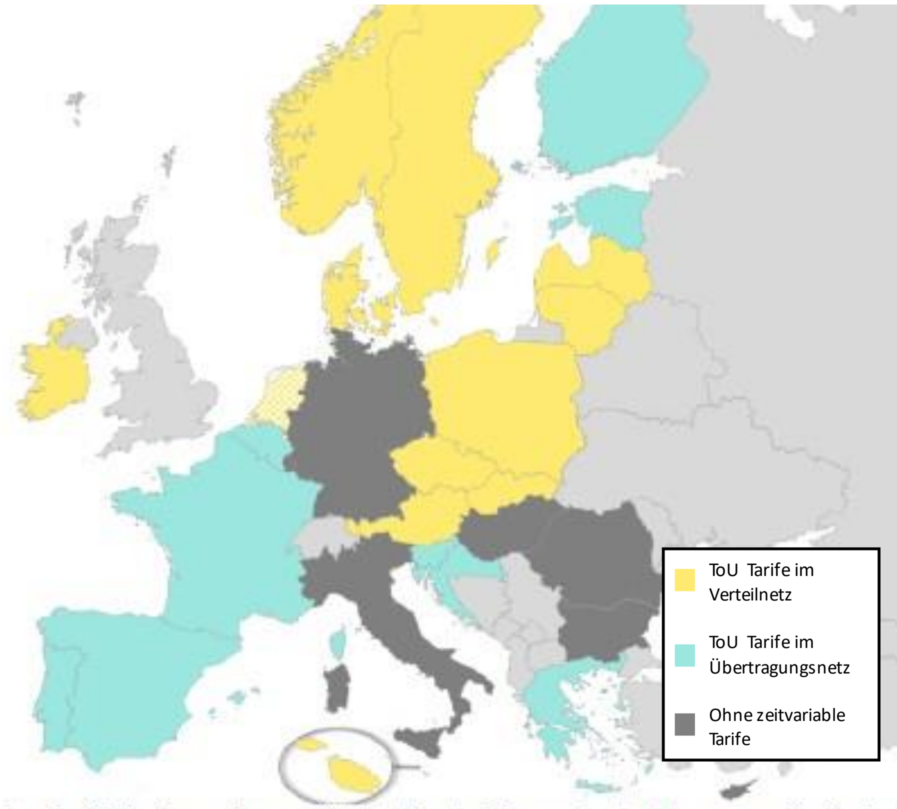

Figure 6. Time-variable grid charges in Europe. Source: ACER (2023)

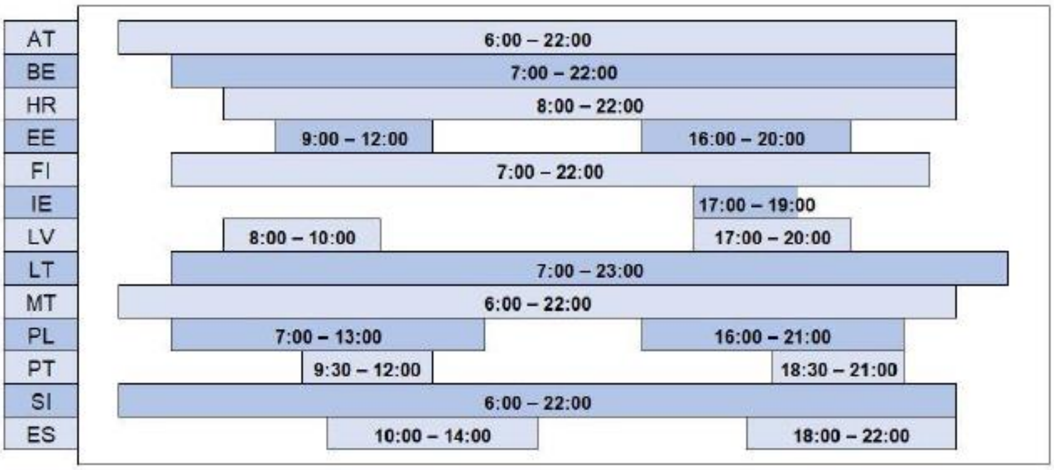

Figure 7. High price time window for distribution grid charges. Source: ACER (2023)

5 Outlook

Decentralized flexibility. In view of the increasing flexibilization of electricity demand, we recommend that grid charges be understood more in terms of incentive aspects and developed accordingly. This is the only way to prevent distribution grids from being overloaded without distribution grid operators taking over the complete control of flexible systems in private households.

Hen's egg. In Germany, there are no time-variable grid charges for small end customers and time-variable end customer tariffs are still in their infancy. It is therefore hardly surprising that technology, algorithms, interfaces and business models for demand-side flexibility are still largely lacking.

Innovation policy. The introduction of time-variable grid charges for households is therefore essentially innovation policy. It is not about realizing significant flexibility potential in the short term. Rather, in view of the increasingly rapid growth of heat pumps, electric cars and home storage systems, the course should now be set for the technical, regulatory, contractual and economic development of decentralized flexibility. For time-variable grid charges, this means that a step-by-step approach, pragmatic solutions, clear public communication and regular evaluation appear to make more sense than an academic search for the theoretically best system. For example, an approach based on the following modules seems plausible:

- Module 1: Static time-variable grid charges for small consumers
- Module 2: Reform of the grid fee system for RLM customers

- Module 3: Pilot project for the regional reduction of grid charges during periods of strong winds
- Module 4: Integration of modules 1 to 3 into a coherent system
- Module 5: Refinement

Module 1: The short-term introduction of static, time-variable grid charges for small consumers, as is already common practice in most other European countries, appears to be an essential element. This should preferably be done in distribution grids where congestion of relevant grid elements is well described by calendar time, which should apply in particular to urban and suburban distribution grids characterized by load, as well as those dominated by solar power generation.

Module 2: A far-reaching reform that is essential in the medium term is that of the grid fee system for RLM customers. We are convinced that not only the exemptions in Section 19 StromNEV, but also the capacity charge should be fundamentally reformed. Both could possibly be replaced by a sensibly designed time-variable grid fee.

Module 3: In parallel, we consider a pilot project for the regional reduction of grid fees in times of strong winds in Schleswig-Holstein and Hamburg to be sensible.[1] Whenever many wind turbines have to be curtailed, the grid charges of all load metered consumers in the same region are dynamically reduced. This creates incentives to make electricity demand more flexible and the temporary and regionally limited increase in electricity consumption creates additional green added value through otherwise curtailed renewable electricity. This approach is part of various measures for utilization instead of curtailment and is aimed in particular at increasing the flexibility potential of small consumers.

Module 4: While modules 1 to 3 can be developed and implemented in parallel, module 4 will follow. In this model, based on the experience gained, modules 1 to 3 will be merged into a coherent, Germany-wide grid fee system that combines static and dynamic elements where necessary.

Module 5 In the long term, with advancing automation and digitalization as well as better load flow measurement technology on the part of the grid operators, the temporal and spatial resolution of time-variable charges will be refined and lead times shortened so that grid charges increasingly accurately reflect the actual, current situation in the individual grid lines.

[1] See: https://www.agora-energiewende.de/blog/windstrom-nutzen-statt-abregeln/