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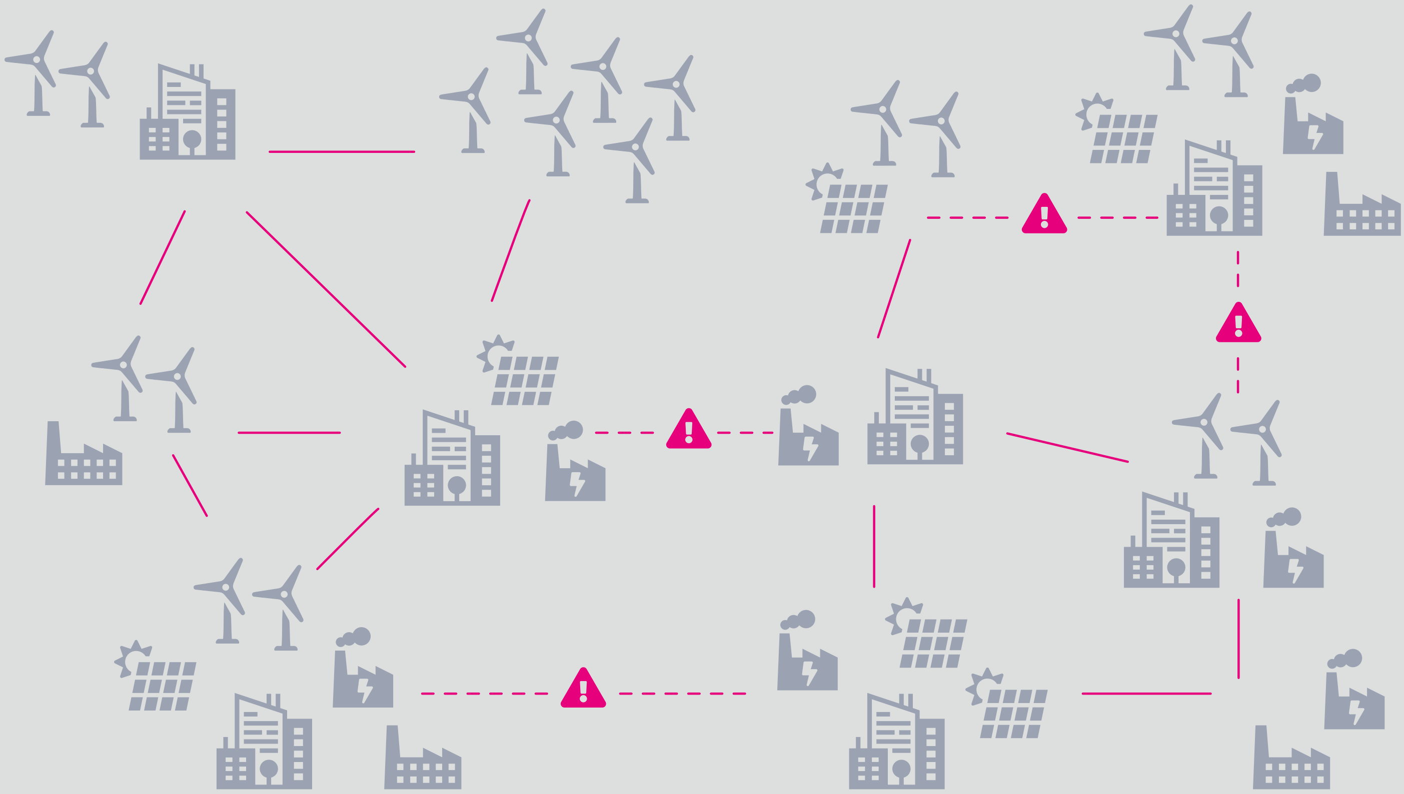
Position paper

Grid Congestion as a Challenge for the Electricity System

Options for a Future Market Design



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Grid Congestion as a Challenge for the Electricity System

Options for a Future Market Design

Preface

In the first quarter of 2020, for the first time more electricity from renewable than from conventional energy sources was fed into Germany's electricity grid. This marks an important milestone on the way to a climate-friendly future. Increasing numbers of renewable energy units, ranging from offshore wind farms to domestic solar units, are coming on-stream and contributing to a low-emission energy supply.

This trend remains a challenge for electricity grid operators. Firstly, electricity generation from wind and solar units varies hugely depending on weather conditions. Secondly, increasingly large volumes of electricity from the windy northern part of Germany have to be transported to the major industrial centres in the south and west of the country. Grid operators already nowadays have to manage grid congestion, i.e. situations in which the capacity of the electricity grid is insufficient to transport the volumes of electric power required to meet demand. To this end power plants and storage units are instructed to adjust their operating schedules in return for remuneration.

Grid congestion management costs came to some 1.4 billion euro in 2018 and some 1.2 billion euro in 2019. It is to be expected that this issue will become more acute since, in addition to the expansion of renewable energies, new electricity demand for electric vehicles, heat pumps and electrically powered industrial processes, as well as the expansion of cross-border electricity trading, will also contribute to grid congestion.

Ensuring a stable electricity supply is, however, essential for consumers and for Germany's industry and commerce. The necessary grid expansion is governed by protracted planning procedures. Besides, grid expansion is not always the most favourable solution for eliminating grid congestion.

This position paper, which is part of the Academies' Project "Energy Systems of the Future" (ESYS), discusses how changes to the current design of the electricity market can help to manage grid congestion. The researchers set out five options for action and identify their respective advantages and drawbacks. Their conclusion is that, while no single one of the suggested measures can solve the problem, various combinations can help to ensure a reliable, less costly and environmentally friendly electricity market design.

We would like to express our sincere thanks to the scientists and reviewers for their commitment.

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Abbreviations and units

AbLaV	Interruptible Loads Ordinance
BDI	The Federation of German Industries
BEHG	Fuel Emissions Trading Act
BKartA	Federal Cartel Office
BMWi	Federal Ministry for Economic Affairs and Energy
BNetzA	Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway
Dena	German Energy Agency
EEG	Renewable Energy Expansion Act
EFET	European Federation of Energy Traders
EnWG	Energy Industry Act
ERCOT	Electric Reliability Council of Texas
EU ETS	European Union Emissions Trading System
EU	European Union
E-mobility	Electromobility
HVDC lines	High-Voltage DC transmission lines
ISO	Independent System Operator
KWKG	Combined Heat and Power Act
MISO	Midcontinent ISO
NetzResV	Grid Reserve Ordinance
PV	Photovoltaics
SO GL	System Operation Guideline
OTC	Over the Counter (direct trading, off-exchange trading)
StromNEV	Grid Fee Ordinance
TSO	Transmission system operator
DSO	Distribution system operator
PE-X	Crosslinked polyethylene

eurocent/kWh	eurocent per kilowatt-hour
TWh	Terawatt-hour
%	Per cent

Glossary

Adjustment measures	Emergency measures taken by a grid operator to ensure secure and reliable transmission grid operation. To achieve this, grid operators can adjust electricity feed-ins, transits and extractions.
Bid-Ask Spread	Difference between the prices purchasers (on the electricity exchange) are prepared to pay and the prices sellers would like to achieve.
Brownout	Drop in voltage in the electricity grid or (in the present context) an intentional load reduction by disconnecting specific consumers from the grid to achieve local limitation of a power failure and so prevent complete supply failure (a blackout).
Clean Energy Package	The EU's legislative package "Clean energy for all Europeans" is the basis for the implementation of the European Energy Union and the 2030 EU Climate and Energy objectives. It includes four directives and four regulations, which came into force in 2018 or 2019. The aspects of relevance here are in particular the Regulation (EU) on the internal market for electricity and the Directive concerning the internal market in electricity.
Countertrading	Offsetting electricity trading across bidding zones with the aim of counteracting grid congestion. Electricity is bought "downstream of the bottleneck" and sold "upstream of the bottleneck". Countertrading is organised by the transmission system operator whose grid is affected by the congestion.
Dispatch	Dispatch planning by plant operators for their power plants (and storage devices) on the basis of the concluded electricity trading transactions.
Feed-in management	Curtailment by the grid operator of units which enjoy feed-in priority under the Renewable Energy Sources Act (EEG 2017) or the Combined Heat and Power Act (KWKG) to relieve grid congestion.
Emissions Trading System (ETS)	A cap & trade system established by the EU, in which an upper limit or cap is set for the emission of specific substances and a number of certificates is provided which corresponds to these emissions. These certificates can be traded between emitters. The ETS regulates the emission of specific greenhouse gases for specific sectors within the EU.
Congestion management	Used in this position paper to encompass any instruments which serve to pre-emptively prevent the risk of grid congestion (congestion avoidance) or overcome an existing risk of grid congestion (congestion elimination).
Bidding zone	Electricity market area in which a uniform wholesale electricity price applies. Within a bidding zone, no account is taken of line capacity – and thus also of potential grid congestion – when trades are concluded.
Inc-dec gaming	Relates in this position paper to bidding behaviour in which market participants increase or decrease their bids on the spot market to maximise their returns through offsetting on the flexibility market.

Nodal pricing system	In a nodal pricing system, the electricity prices for each grid node (i.e. for each injection point and each extraction point of the electricity grid) are in principle calculated separately. In this way, the transmission capacity of the electricity grid is taken fully into consideration in electricity price setting.
Grid congestion	Situations in which the capacity of the electricity grid is insufficient to meet transmission demand.
Grid reserve	Power plants making up the grid reserve are kept in reserve by TSOs in order to guarantee the security and reliability of the electricity supply system, in particular for the purpose of redispatch. They do not participate in the electricity market.
Power-to-X technologies	Conversion of electric power into other energy forms (X) such as heat or chemical energy sources (e.g. hydrogen or synthetic methane)
Redispatch	To relieve impending grid congestion, grid operators instruct power plants and storage devices up- and downstream of the grid bottleneck to adjust their operating schedules (dispatch).
Spot market	On the spot market, short-term electricity trades are concluded. The spot market essentially consists of a day-ahead market and an intraday market. On the day-ahead market, trading for the following day is closed at midday with an auction (market clearing). Trades on the intraday market can be concluded from 15:00 on the preceding day in order to balance short-term shortages or surpluses.
Unbundling	The term "unbundling" denotes the separation of the information, accounting, company law, operational and possibly ownership aspects of electricity grid operation from the generation, storage, trade and sales of electricity. It is intended to guarantee grid operation independence and thus prevent discrimination, cross-subsidies and other distortions to competition and in this way to ensure the same competitive conditions for all market participants.

Summary

The energy transition and the European Energy Union are placing new requirements on electricity grids. Any ongoing grid congestion may well cause high costs and additional risks to grid stability, which can be countered by adjusting the market design. This position paper sets out five policy options. The following points may be noted:

- Suitable **price signals** can ensure that the available transmission capacity is taken into account in dispatch decisions for generation, storage and consumption units. Thereby, grid congestion is **preemptively addressed**. Such signals can apply both to the wholesale electricity price and to grid fees. Such approaches should be more thoroughly investigated.

- **Utilisation-based grid fees** have the advantage that they can be incorporated into the system of a uniform German electricity bidding zone. Such an approach would, however, first have to be developed and trialled.

- **Market-based procurement of flexibility** for eliminating subsisting grid congestion fits well with the guiding principle of a competition regime. It would provide incentives to make better use of flexibility potential, specifically on the load side, and to tap any innovation potential. The functioning of electricity and flexibility markets would, however, have to be monitored. The same applies if increased financial incentives were to be added on to the current cost-based procurement system. Such approaches should be pursued.

- All the policy options have their **advantages and drawbacks**. A **combination** of measures should therefore be considered in order to achieve the best possible outcome.

New market design needed for the energy transition and the European internal electricity market

A power supply failure or blackout could cause major harm in Germany within a very short time, something which has been made obvious to us in recent years in technical papers, science shows and even novels. A stable power supply is fundamental for all electricity consumers and a decisive factor for the country as a location for industry and commerce. The stability of Germany's supply is always among the very best in Europe and worldwide. In specialist circles, however, a wide-ranging debate has been under way for years as to whether, as the energy transition progresses and cross-border electricity trading increases, changes to market design are necessary.

The energy transition and the European Energy Union are exacerbating the challenges facing grid operators who are responsible for ensuring electricity grid stability: rising levels of feed-in from renewable energy units, modified load profiles for new consumers such as electric vehicles, likely growth in electricity consumption and the expansion of cross-border electricity trading are all combining to make **grid congestion** a more frequent occurrence. These are situations in which the capacity of the electricity grid is insufficient to meet transmission demand. **Grid expansion** is not always possible in good time, sometimes difficult to implement due to a lack of acceptance and sometimes not the most favourable solution for ensuring a reliable electricity supply. There is thus a risk of decades of high costs for eliminating grid congestion as well as an increased risk of power outages.

As the market is currently designed, grid operators can intervene in generation unit dispatch in the event of grid congestion. Primarily, conventional large-scale power plants are obligated to adjust electricity feed-in on instruction by the grid operators, but ever fewer such units are available as the energy transition progresses. Subordinately, feed-in by renewable energy units may also be curtailed. There are hardly any incentives for electricity producers and consumers to adjust their electricity feed-in or demand to available grid capacity. Consumption units are called on only very little for congestion management. It should therefore be investigated whether **changes to market design** might in future overcome grid congestion or even nip them in the bud both **more efficiently**, i.e. at lower cost, and **more effectively**. Such a market design would, moreover, have to take account of **European Union requirements** on electricity market design and congestion management. This position paper summarises the current state of knowledge, sets out options as to how grid congestion can be efficiently and effectively avoided and evaluates them against defined criteria in order to provide political decision makers with a basis for further decisions.

How is grid congestion currently eliminated?

Understanding how grid congestion arises at the moment means taking a look at electricity trading: Germany, plus Luxembourg, form a **single bidding zone** for electricity trading. Within this bidding zone, transmission capacity is assumed to be unlimited ("copper plate"). As a result, the wholesale price for electricity is the same throughout Germany. Operators schedule the operation of their power plants and units (dispatch) on the basis of trading operations. **Dispatch decisions** are thus made without taking account of available grid capacity. A complicating factor is the current European drive towards the provision of greater transmission capacity at the bidding zone borders for cross-border electricity trading. This may make grid congestion more acute both at the bidding zone borders and within the bidding zone.

Congestion management measures ensure **security** and **reliability** of the electricity supply. Grid operators in Germany are currently implementing a considerable volume of such measures, the associated costs amounting to around 1.2 billion euro in 2019 or some two per cent of total electricity supply costs. Various options are open to **grid operators** for grid congestion: firstly, they can call on their own resources. If this is not possible, they can instruct third parties to ramp unit output up or down. The most important measures are currently redispatch, which involves operators "upstream" and "downstream" of the grid congestion having to ramp their conventional power plants up or down, and feed-in management, in which grid operators curtail renewable energy units and combined heat and power plants.

Options for an efficient and effective market design

This position paper sets out **five policy options** (see box below), which may be divided into **two categories**: the aim of the first three options is to take greater account of potential grid congestion right from the stage of the electricity transactions and thus during unit dispatchplanning. Grid congestion may consequently be avoided from the outset and grid operators will have to intervene more rarely. The other two options take effect following dispatch decisions and are intended to enable grid operators to procure **flexibility** more efficiently by providing financial incentives for flexibility providers. Both approaches are important for the market design of the future.

The five options are evaluated on the basis of defined **criteria**: effectiveness, efficiency, contribution to climate protection, contribution to the EU internal market in electricity as well as feasibility and reasonable implementation costs. The analysis has shown that there is no single option that is preferable in every respect. All the options have specific advantages and drawbacks which are of greater or lesser significance depending on the assessment. Some of the options may, however, be combined, so to some extent reducing certain drawbacks.

At a glance: Five options for effective and efficient grid congestion management

Introduction of a nodal pricing system (category: dispatch)

- **Brief description**: In a nodal pricing system, a power price is set for each grid node, i.e. for each feed-in and extraction point, with grid congestion being taken into account. This may result in power prices which vary regionally or even locally.
- **Advantages**: An ideally functioning nodal pricing system models grid congestion perfectly; no congestion management measures are required. Conceptually, it is therefore an excellent model.
- **Drawbacks**: Very high implementation costs, in particular if the distribution grid level is included. Operation of the grid must in part be uniformly managed, which would seem to be problematic for grids operated by different operators, particularly for cross-border transfers. There is also an increased risk of individual flexibility providers in favourable locations gaining market-dominating positions.

Reconfiguration of the uniform German electricity bidding zone (category: dispatch)

- **Brief description**: Structural congestion is addressed by reconfiguring the electricity bidding zone (e.g. splitting into two price zones, one northern and one southern). Insufficient transmission capacity at the bidding zone borders may result in different power prices in the individual bidding zones.
- **Advantages**: Grid operators have to intervene more rarely in the unit operators' dispatch, thus effectiveness is increased and the costs of interventions are lowered.
- **Drawbacks**: Rigid bidding zone borders can never completely model grid congestion. Future changes in grid usage and expansion may make adjustments necessary. Additional costs may arise for power trading. Differing power prices are a delicate political issue in Germany. Grid congestion within bidding zones still remains, in particular at the distribution grid level.

Introduction of utilisation-based grid fees (category: dispatch)

- **Brief description**: In a utilisation-based tariff system, the grid fees payable by electricity consumers and possibly by generators on feed-in are higher when grid utilisation is critical than when it is low, with both location and timing playing a determining role.
- **Advantages:** Power market liquidity is maintained. Grid operators need to intervene in dispatch more rarely, so reducing costs. Potentially highly effective, but dependent on appropriate configuration.
- **Drawbacks:** Setting adequate grid fees is complex and their steering effect is currently almost impossible to estimate. There is a lack of practical experience and a major need for research.

Expansion of market-based procurement of flexibility (category: flexibility)

- **Brief description**: Flexibility for congestion management is procured by methods in which remuneration is (largely) freely negotiated between flexibility provider and grid operator, with the lowest cost offers, for example via regional flexibility markets, being selected.
- **Advantages**: Potentially lower costs thanks to additional flexibility offers and innovation. In particular, incentives are created for flexible load providers, such as commercial or industrial consumers.
- **Drawbacks**: The market power of individual providers can compromise the funtioning of the market. Strategic bidding behaviour can raise flexibility demand and costs. Regulatory control of power and flexibility markets is required.

Increased incentives for non-market-based procurement of flexibility (category: flexibility)

- **Brief description**: Flexibility for congestion management is procured via expressions of interest. Remuneration is as far as possible on a costs basis supplemented by additional financial incentives for the flexibility provider.
- **Advantages and drawbacks**: Similar to those for market-based procurement. Lower incentives for flexibility providers but also lower cost risks for grid operation.

Addressing congestion preemptively to save costs and reduce risks

Under the current framework, considerable grid congestion will probably still continue to occur for decades. This would suggest the need to adapt the market design in order to **preemptively prevent congestion** and thereby improve effectiveness and cost-efficiency. Three options would appear to be very promising here: changeover to a nodal pricing system, reconfiguration of the German electricity bidding zone and further development of the grid tariff system towards utilisation-based grid fees (options 1 to 3, category "dispatch"). The following points may be made:

Nodal prices: Theoretically ideal but very demanding to implement

- An ideally functioning nodal pricing system is capable of **completely factoring in grid congestion in electricity price setting**. As a result, grid operators need to intervene at most only to a very limited extent in unit dispatch. At the same time, providing generation costs and transmission capacity are correctly modelled, the generation units used are those which are capable of meeting electricity demand at the overall lowest costs. Nodal prices are used in some regions of the world.
- However, considerable objections may be raised against a nodal pricing system: its introduction entails root and branch reform of the current market design. **Practical implementation would be very complex,** in particular if distribution grids were to be included. Distribution grids are, however, becoming increasingly significant due to the energy transition, and grid congestion in the transmission and distribution grids may be interlinked.
- In addition, the grid operators involved in a nodal pricing system would have to **hand over some areas of authority** to a central body. This intervention in their present responsibilities is a considerable impediment to implementation, most particularly for the creation of cross-border nodal pricing systems. Furthermore, the earnings potential for market participants in a nodal pricing system is heavily dependent on the organisation of the pricing rules and the decisions taken about the operation, maintenance and expansion of the grid. **Regulatory controls for ensuring that grid transactions are conducted in a non-discriminatory and transparent manner will therefore have to be stricter** than at present. Finally, nodal electricity prices might raise electricity trading costs as a result of lower liquidity and increase the **risk** of individual market participants assuming **market-dominating positions**.
- A nodal pricing system is therefore not currently considered to be the **priority policy option**. A hypothetical, ideally functioning nodal pricing system may, however, serve as a **benchmark** for other market design options.

Reconfiguration of bidding zones: can reduce costs but effects are limited

- **Reconfiguration, for example splitting, of the German electricity bidding zone,** would address **structural congestion** from the electricity trading stage onwards and thus during dispatch. The better the new bidding zone borders map structural congestion in the transmission grid, the **fewer interventions will be required in unit dispatch**.

- However questions remain in terms of effectiveness and efficiency: since electricity flows vary by time of day and seasonally, **grid congestion can never be completely modelled by rigid bidding zone borders**. Changes in grid usage and grid expansion may in future also displace structural congestion, so possibly entailing regular adjustment of zone borders, something which is always a **very costly** process. Moreover, **liquidity on electricity markets might decline,** possibly resulting in increased wholesale electricity prices. This is also the lesson learned from splitting bidding zones in Sweden and splitting the German-Austrian bidding zone. The effects on wholesale electricity prices would have to be investigated in greater detail so they can be weighed up against the cost benefits of reconfiguring the bidding zone.

- If bidding zones were made relatively large, for example a northern and a southern German bidding zone, **grid congestion within bidding zones** would to a considerable extent **remain in place**. In particular, grid congestion in distribution grids is not generally taken into account when bidding zones are configured.

Utilisation-based grid fees: potentially efficient, but untested

- Utilisation-based grid fees provide **incentives to make preferential use of the electricity grid in times when transmission capacity is available**. They can identify grid congestion within bidding zones and would therefore be possible even if electricity bidding zones remain in place. **Electricity market liquidity would in principle be retained**.

- Utilisation-based grid fees would nevertheless also be **complex** to introduce. Such a tariff system would firstly have to be devised and its steering effect tested. Very little experience is available as yet. A decision would have to be made about how far grid fees should be **differentiated by congestion regions and times**. In addition, apportioning the costs of congestion management to specific grid users is a **very inexact science**. Finally, **effects on electricity prices** would have to be investigated.

- Achieving an efficient system might also entail extending grid fees to **electricity feed-in suppliers**. At present, only electricity consumers pay grid fees. Furthermore, grid users must be able to influence the level of grid fees by their behaviour. This is not the case for small customers (generally private households) under the currently used **standard load profiles**. In addition, various **fixed electricity price components** such as the EEG surcharge and electricity tax may reduce the incentive effect.

Providing financial incentives to boost the efficiency of flexibility procurement

Even if some grid congestion can be preemptively prevented, **dispatching flexibility** will probably remain necessary to eliminate congestion. This should be done as efficiently as possible. Since conventional large-scale power plants are increasingly going off-line, the significance of flexibility from smaller generation and storage units and from consumption units is simultaneously rising. It is important to improve the availability of flexibility from such units. Financial incentives, which purely cost-based remuneration cannot offer, would seem to be a sensible way of achieving this. An expansion of market-based procurement and increased incentives for non-market-based procurement of flexibility (options 4 and 5, category "flexibility") may be considered. An analysis yields the following results:

- Both options would provide financial incentives to increase the **supply of flexibility** and release innovation potential. In particular, incentives would be created for flexible **load** providers, such as commercial or industrial consumers, a potential which is at present largely untapped.
- Market-based procurement fits well with the guiding principle of a competition regime. The **new EU legislative provisions** set out in the Clean Energy Package also make market-based measures the basic principle for procuring flexibility. Barring any sound reasons to the contrary, **market-based approaches** such as regional flexibility markets should thus be further investigated. Market function may in particular be disrupted by individual providers' market-dominating positions.
- If **non-market-based procurement** of flexibility continues to be applied, it should be investigated to which extent additional financial incentives may be capable of expanding the supply of flexibility and innovation, and whether the value of this flexibility exceeds the costs of the additional financial incentives. In the case of flexible loads for which cost-based remuneration cannot be determined, the remuneration could be limited by the most inexpensive alternative flexibility option for which a cost-based calculation is possible.
- Both options involve a risk of **strategic bidding behaviour**: market participants could withhold bids from the electricity market and subsequently market their supply or demand as flexibility at a better price. This may firstly increase flexibility demand from grid operators and secondly raise procurement costs. In an extreme case, market participants could make bids on the electricity market in order to have them "bought" back again as flexibility. Electricity markets and flexibility procurement would have to be **monitored** in order to counter such risks.

	Option 1 Introduction of a nodal pricing system	**Option 2** Reconfiguration of the electricity bidding zone	**Option 3** Introduction of utilisation-based grid fees	**Option 4** Expansion of market-based procurement of flexibility	**Option 5** Increased incentives for non-market-based procurement of flexibility
Category	Dispatch	Dispatch	Dispatch	Flexibility	Flexibility
Affected grid levels	Primarily extra-high- and high-voltage grid	Extra-high-voltage grid	Primarily extra-high-, high- and medium-voltage grid	Primarily extra-high-, high- and medium-voltage grid	Primarily extra-high-, high- and medium-voltage grid
Effectiveness	High	Higher than in the current situation. The better grid congestion is represented, the more effective they are	Depending on configuration, moderate to high	Higher than in the current situation	Higher than in the current situation
Short-term costs	Greatly reduced flexibility demand Risk of cost increases for electricity trading	Reduced flexibility demand Risk of cost increases for electricity trading	Reduced flexibility demand Effects on electricity trading merit closer investigation	Greater flexibility supply Risk of market power, inc-dec	Greater flexibility supply Risk of higher flexibility costs, inc-dec
Climate protection contribution	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation
Contribution to EU internal market in electricity	Cross-border application difficult	Highly compatible	Neutral	Highly c ompatible	Highly compatible
Feasibility and implementation costs	Low feasibility, very high implementation costs	High and possibly recurrent implementation costs	Very high for the development of a f utilisation-based tariff system, high for ongoing implementation	High implementation costs	Moderate implementation costs
Option combinable with …	Options 3, 4, 5	Options 3, 4, 5	Options 1, 2, 4, 5	Options 1, 2, 3, 5	Options 1, 2, 3, 4

Table 1: Comparison of policy options

1 Introduction

Central studies into the future of Germany's energy supply indicate that electricity consumption will rise considerably in future, in particular in transport and heating applications, because only the changeover to electricity from renewable sources will allow to achieve the necessary level of reduction in greenhouse gas emissions.[1] In the light of climate protection, electricity from wind and photovoltaic units will become the dominant energy source of the future.

As a consequence, electricity grids are coming increasingly into the focus. On the one hand, these need to be expanded so they are capable of transmitting the larger volumes of electricity. On the other hand, the required specifications of grids are changing with feed-in from renewable energy units rising on the generation side. In contrast to generation in conventional power plants, such feed-in may vary greatly over time. The demands placed on grids from the load side are changing too, with the addition of many new consumer or customer applications which have different load profiles, such as electric vehicles, heat pumps and power-to-X technologies. Further integration of the "European Energy Union" will also place greater demands on electricity grids. These trends have an impact on spatiotemporal grid utilisation. Transmission capacity will therefore often not be sufficient to execute all desired electricity trades. Handling such grid congestion is a major challenge for what is already a complex grid control task and will have a decisive influence on making the energy transition a success.

Typical grid congestion situations during the energy transition

Expansion of both onshore and offshore wind energy in northern Germany, increasing feed-in into distribution grids from decentralised generation units and rising power consumption in particular by electromobility and heat pumps are leading to typical congestion situations, specifically:

1. Congestion in the transmission grid between northern and southern Germany, especially in strong winds
2. Local congestion in the distribution grid due to feed-in from wind and solar farms
3. Congestion in the low-voltage network due to high grid loads from new sector coupling consumers (e.g. electromobility, heat pumps)

Grid congestion jeopardises **security of supply**[2]**, in particular grid and system security.** "Congestion management" measures must therefore be taken to maintain security of supply to the greatest possible extent despite limited transmission capacity. Congestion management generates costs: in 2019, grid operator costs for such measures came to some 1.2 billion euro,[3] or around two per cent of total electricity supply

1 acatech/Leopoldina/Akademienunion 2017; ESYS/BDI/dena 2019.

2 Supply bottlenecks may also occur independently of grid congestion if power demand exceeds supply, for example in the case of insufficient power generation when wind and solar energy supplies are low. Such bottlenecks are, however, not the subject of this investigation.

3 BNetzA 2020.

costs (electricity grids and generation).[4] Grid congestion can, in principle, be avoided by greater **grid expansion.** Studies have shown that grid expansion is generally an inexpensive option for avoiding grid congestion. If the energy transition in Germany and Europe is to be a success, transmission and distribution grids must be further expanded.[5] In practice, however, grid expansion will not completely stop grid congestion from occurring for three main reasons:

Firstly, grid expansion "to the last kilowatt-hour" makes no economic sense. In other words, designing grids to be capable of transmitting maximum electricity generation volumes would result in high costs. For example, wind power units often generate distinctly more electricity for a few, particularly windy hours each year than they do as an annual average. Instead of designing grids for these few hours, it is more inexpensive to curtail electricity feed-in ("peak capping") or reduce transmission demand in some other way (buffer storage, demand control).

Secondly, protracted planning and licensing procedures and sometimes low levels of public acceptance in Germany mean that grid expansion is progressing only slowly. It is therefore to be expected that actual transmission capacity will continue to lag behind transmission demand for some considerable time.

Thirdly, Germany's regulator, the Federal Network Agency, only confirms those grid expansion measures which are necessary on the basis of various energy sector developments ("no regret" measures).[6] Possible lead times are therefore limited.

Effective and simultaneously efficient congestion management will accordingly be required even in the long term in order to maintain security of supply while simultaneously keeping costs as low as possible. There are various **market design** options for avoiding or eliminating grid congestion. This position paper sets out the following five options with their advantages and drawbacks:

- Introduction of a nodal pricing system,
- Reconfiguration of the German electricity bidding zone,
- Introduction of utilisation-based grid fees,
- Expansion of market-based procurement of flexibility for congestion management and
- Provision of increased incentives for non-market-based procurement of flexibility.

Criteria for evaluating these options are stated in section 2. Section 1 will, however, start out by explaining some basic technical principles and how grid congestion is currently handled.

4 See Fraunhofer ISI et al. 2017; BMWi 2019-1.
5 See for example acatech/Leopoldina/Akademienunion 2020-1.
6 BNetzA 2019.

1.1 Basic technical principles

Operating electricity grids is a demanding task. Injection and extraction must match at every point in time. The system's **energy balance** must thus remain at equilibrium. In addition, **voltage** throughout the grid must be maintained within admissible voltage bands, i.e. within a specified voltage range. Furthermore, **current flows** must not exceed the load limits of the grid infrastructure. Grid operators need the assistance of grid users in order to fulfil these requirements with regard to balancing the system, maintaining voltage level and admissible load. In particular, operators of generation, storage and consumption units must adjust their injection or extraction accordingly. This ability to adjust injection or extraction is known as **flexibility.** The nature and scope of flexibility provision for grid operation are partially set out in law and are part of the "**market design**" (see also the "unbundling" box in 1.3.1).

Network components

Network components is the name for electrical equipment which is used by a grid operator for grid operation. It includes overhead power lines, cables, transformers, switchgear, substations and associated control and protection technology and, in exceptional cases, also storage units and power plants, providing the grid operator only holds them in reserve for grid operation.

Network components may, but need not necessarily, be in the grid operator's ownership or possession. The defining factor is that the grid operator uses them exclusively for operating the grid. Units which third parties make available only temporarily to the grid operator for grid purposes are thus not network components.

Major **technical parameters** during grid operation are active power, reactive power, voltage, frequency and current flow:[7]

- Electricity grids in Germany are generally operated with **alternating current**.[8] The electrical power is here made up of active power and reactive power.

- **Active power** is the proportion which can be converted by consumers into other forms of energy such as mechanical work, light or heat, and so be "consumed".

- **Reactive power** is required for alternately creating and destroying electrical and magnetic fields in generation, storage and consumption units and in grid infrastructure.[9] Creating the fields requires energy which is released again when the fields are destroyed, so that the energy may then be used once again to create the fields. Reactive power is therefore strictly speaking not actually "consumed", but exchanged between generation, storage and consumption units and items of grid infrastructure. Transmitting reactive power does, however, involve losses. Reactive power is required for grid operation, in particular for maintaining voltage level but also for operating generation, storage and consumption units.

7 There are also further electrical engineering parameters which are of significance to grid operation but they will not be looked at in any greater detail here. These include short-circuit power, voltage angle and the various kinds of stability: static and transient stability and voltage stability (as opposed to voltage level).

8 Strictly speaking, the electrical energy supply is composed of three subsystems with alternating current which are jointly known as a three-phase system. Exceptions are "high-voltage, direct current" (HVDC) transmission lines which are operated with direct current. Power losses are lower in HVDC transmission lines, which is why they may primarily be used for long-distance transmission. They also use simpler cable technology.

9 Direct current therefore has no reactive power component, only active power.

- Maintaining a stable **line frequency** for alternating current requires active power injection and extraction to match at every point in time. If injection is greater than extraction, line frequency rises. If it is smaller, line frequency falls. Relatively large deviations from nominal frequency can result in a power supply outage: the line frequency exceeding or falling below a specific tolerance range results in disconnection of generation units from the grid or in automatic distribution grid load shedding. A stable line frequency with slight deviations is therefore an important indicator of electricity supply security. Nominal line frequency in Europe is 50 hertz. In order to maintain line frequency stability, transmission system operators (TSO) procure and make appropriate use of what is known as a control reserve (primary control reserve, secondary control reserve and minute reserve) from generation, storage and consumption units.

- Similarly to a stable frequency, a stable **voltage** in the electricity grid is an important factor in not only security but also quality of supply. Excessively high voltages can damage not only grid infrastructure but also generation, storage and consumption units, while excessively low voltages can lead to malfunctions or impair available transmission capacity. Voltage along a power line declines as a function of current load. A grid operator must therefore take additional action to maintain voltage in the entire network within the intended voltage range or band by means of load-following transformers, reactive power feed-in from generation and storage units or particular network components, in the form of reactive power compensation units (charging current coils or capacitors).

- Any transmission of active and reactive power is associated with an electrical **current flow**. Current flows lead to losses and heating of overhead power lines, cables and transformers. In overhead power lines, heating may lead to excessive sagging. In cables and transformers, excessive heating affects the insulating properties of the dielectric materials used in them, for example crosslinked polyethylene (PE-X) or oil. Grid infrastructure has a maximum admissible current flow to avoid such phenomena.

Grid congestion occurs when transmission demand exceeds the available electricity transmission capacity. Certain safety margins must be observed when determining available transmission capacity, meaning that grid congestion may occur even when transmission demand can still be handled physically.[10] In particular, it should generally be ensured that the grid can still be securely operated even after failure of one important element (e.g. a line or a power plant) (N-1 security).[11] Grid congestion jeopardises the security and reliability of the electricity supply: excessive grid loads can result in grid infrastructure failing or being damaged and consequently preventing generating units from feeding in or consumers from being supplied. Grid congestion may moreover prevent the desired volumes of electricity trades being executed, which in turn endangers security of supply for the electricity consumer.

10 Möhrke et al. 2019.

11 Alternatively, curative provision of N-1 security is currently being discussed in which, after grid faults, automated systems immediately reestablish N-1 security, see for instance BMWi 2019-2; Möhrke et al. 2019.

There are, however, technical differences between **current-related and voltage-related** grid congestion. **Current-related** grid congestion involves the permissible current loading of grid infrastructure being exceeded. In this case, congestion management relieves the load on the affected grid infrastructure. One measure is for example redispatch, which involves adjusting active power injection or extraction "upstream" and "downstream" of the grid congestion (see 1.2.2 below). If the power flows causing the congestion are brought about by high injection, injection must fall or extraction must rise upstream of the congestion. This can be achieved for example by generation units cutting injection or consumption units extracting more. Downstream of the congestion, injection must rise or extraction fall (energy balancing). Conversely, in the case of load-side grid congestion, extraction must be reduced or injection increased downstream of the congestion. In this case, injection must fall or extraction rise upstream of the congestion. Adjustments to injections and extractions must not disturb the balance of the system. In addition, the line frequency of 50 hertz must be maintained.

Power grids

Germany has four **transmission system operators (TSOs)**, each of which has responsibility for a **control zone**. The TSOs operate extra-high voltage grids for transmitting power over long distances. The transmission grid circuit length totals some 37,000 kilometres.

With a low-voltage circuit length of 1,190,000 kilometres, a medium-voltage circuit length of 520,000 kilometres and a high-voltage circuit length of 94,000 kilometres, **distribution grids**, on the other hand, make up 98 per cent of Germany's overall power grid. However, they figure much less frequently in the debate in society than the transmission grids, with their large, conspicuous pylons. While distribution grids have previously primarily been responsible for transmitting power from the transmission grid to individual end consumers, they are assuming new tasks as the energy transition progresses. This is because increasing volumes of power are being fed directly into the distribution grids from decentralised renewable energy units. Many of Germany's some 900 **distribution system operators (DSO)** in the power sector are part of regional or municipal energy supply companies.

In **voltage-related** grid congestion, the admissible voltage bands cannot be maintained.[12] The remedy generally involves adjusting reactive power feed-in during congestion management.[13] If power plants are dispatched to provide the necessary reactive power, it may be necessary to adjust their active power feed-in. This is achieved by starting up idle power plants to minimum active power feed-in or by reducing feed-in from power plants running at full load.[14] In this case, the modified active power feed-in must be balanced in energy terms. Instead of adjusting reactive power feed-in, active power redispatch can in part also ensure compliance with the voltage band – this measure is sometimes even more efficient in the distribution grid.

In the **long-term,** grid congestion can be avoided by **grid expansion**. **Site selection** for generation, storage and consumption units may also make a long-term contribution to reducing grid congestion. **In the short term, grid operators have to intervene** when a specific instance of grid congestion is anticipated or has already occurred. Affected grid operators can dispatch their own or third party grid infrastructure

12 BNetzA/BKartA 2019.

13 This study does not discuss the adjustments made to reactive power feed-in or withdrawal to ensure compliance with voltage limits since such adjustments affect another service and another type of flexibility for which market design must be separately investigated.

14 BNetzA/BKartA 2019.

(generation, storage and consumption units) to eliminate the congestion. Grid congestion may additionally be reduced by a **suitable regulatory framework**: market participants may receive incentives for factoring in potential congestion in their **dispatch decisions for their generation, storage and consumption units**. This permits regionally differentiated electricity prices which take account of grid congestion, or grid fees which encourage dispatch for avoiding congestion. These measures apply equally to transmission and distribution grids.

The term "**congestion management**" used in this position paper encompasses any instruments which serve to pre-emptively prevent the risk of grid congestion (congestion avoidance) or overcome an existing risk of a grid congestion (congestion elimination). Ultimately, the aim is to eliminate as far as possible any congestion-related limitations to security of supply. However, the term only includes measures for avoiding or eliminating grid congestion in the short-term, when investment in the grid or in generation, storage and consumption units is no longer an option. Measures for avoiding grid congestion in the long term by providing incentives for grid expansion are not considered. Such investment incentives merit dedicated consideration which lies outside the scope of this study. The same applies to investment incentives in relation to generation, storage and consumption units.

1.2 Current system for eliminating grid congestion

In Germany, it is the electricity grid operators which are responsible for secure and reliable grid operation. Regulations specify the measures which are available to them for avoiding or eliminating grid congestion. A distinction must be drawn between grid congestion which occurs within Germany and that which occurs at the bidding zone borders with neighbouring countries.

Flexibility required for power market and congestion management

Given the increasing share of wind and solar energy in power generation, higher levels of flexibility on the **power markets** are required to offset fluctuations in feed-in. This flexibility can only be provided for the European market if sufficient grid capacity is available at all levels down to the distribution grid. Flexibility is additionally required for **congestion management**. Potential flexibility (e.g. a storage unit) may be dispatched either for equalising the energy balance (balancing group equalisation, system balancing) or for congestion management. These aims interact variably and **under certain circumstances dispatch for one may act contrary to dispatch for the other**. Market activity may accordingly give rise to congestion. For example, dispatching balancing power to balance the system may make a grid congestion more acute. However, the aims sometimes overlap, for instance energy balancing in congestion management assists with balancing the system.

Only limited transmission capacity is provided for electricity trading at the **bidding zone borders** (with the exception of the Germany-Luxembourg border). Subsequent intervention by grid operators in unit dispatch is therefore in principle not required.[15]

15 However, insofar as the transmission capacity made available for power trading exceeds physical transmission resources, grid operators must implement redispatch measures here too. This necessity may in particular arise from EU requirements on minimum cross-zonal trading capacity.

In contrast, within Germany there is a **uniform bidding zone** for electricity trading: injection and extraction locations and transmission capacity within Germany play no part in price setting on the electricity market and in the associated dispatch decisions for generation, storage and consumption units. As a result, all buyers in Germany pay the same wholesale price on the electricity market irrespective of their location and all sellers receive the same price. Electricity is thus traded without taking the available transmission capacity into account. If the anticipated injections and extractions would result in grid congestion, it is the grid operators' responsibility to take countermeasures. If they are to be able to act in good time, grid operators must be able to forecast possible grid congestion. Electricity trading and congestion management within Germany are described in greater detail below.

1.2.1 Electricity trading

Electricity is traded within Germany over a number of time intervals, with long-term electricity trades, for example over months, quarters and years, being concluded on the **futures market**. Futures trading is used to manage risk for the participating companies and does not specify definitive dispatch of generation, storage and consumption units. This is achieved on the spot market which essentially consists of a day-ahead market and an intraday market: on the **day-ahead market,** trades for the following day are concluded in an auction at midday ("market clearing"). Trades on the **intraday market** can be concluded from 15:00 on the preceding day in order to balance short-term shortages or surpluses. Intraday delivery may, for example, be necessary if forecasts of electricity demand or feed-in from fluctuating generation units change in the short term.

Operators of large generation and storage units[16] must notify the TSOs each day by 14:30 of their dispatch plans for the following day. In addition, they are legally obliged to update dispatch plans in the event of major changes.[17] Dispatch plans take account of executed electricity trades on the day-ahead and/or intraday markets. The EU "System Operation Guideline" (SO GL) Regulation[18] imposes further notification obligations on operators of generation, storage and consumption units. TSOs can use such notified planning data and further information to forecast grid congestion for the following day and to adjust these forecasts on the basis of updated information.

1.2.2 Grid operator measures for forecasting and eliminating grid congestion

In parallel with electricity trading, grid operators make calculations with the aim of predicting grid congestion and thus allowing countermeasures to be initiated as early as possible. These calculations likewise proceed in a number of steps. The closer the electricity delivery time becomes, the more planning data are available for generation, storage and consumption units and the more accurately the TSOs are able to forecast grid congestion.

In the course of "joint **initial measures by all 4 TSOs**", the TSOs jointly model anticipated grid loads,[19] both before and after the market outcome ("market clearing") of the day-ahead market. By making the calculations before the market outcome, the

16 with a nominal power of ten megawatts or more and connected to the 110 kilovolt level or higher.

17 The legal basis for this notification obligation is § 12, paragraph 4, Energy Industry Act (EnWG 2020).

18 Regulation (EU) 2017/1485, see article 40, paragraph 7.

19 BNetzA/BKartA 2019, p. 127.

TSOs are able to identify grid congestion in good time, so putting them in a position to be able to request **grid reserve** power plants with a longer lead time in good time for congestion management.[20] A similar situation applies for market power plants. Thanks to their lead time, the congestion management request can be made shortly after the market outcome. The joint modelling and requests means that these power plants can be efficiently dispatched for congestion management ("coordination gains").

After the initial measures the four TSOs jointly identify **individual congestion management measures**, which eliminate grid infrastructure overloads in the TSOs' control zones or on the interconnectors between control zones. The analyses required for this purpose firstly make use of the market participant data transferred under the notification obligations together with further information. The grid operators secondly take account of previously decided joint initial measures. In these calculations, the grid operators firstly establish whether they anticipate grid congestion, taking appropriate individual overload measures for congestion management if they do. Grid utilisation is likewise in part forecast at the distribution grid level.

Legislation and regulations

EU law

- Regulation (EU) on the internal market for electricity, 2019/943
- Directive 2009/72/EC concerning the internal market in electricity; the new Directive (EU) 2019/944 is set to be implemented by 31.12.2020
- Regulation (EU) 2017/1485 transmission system guideline (SO GL)

German law

- Energy Industry Act (EnWG)
- Renewable Energy Sources Act (EEG 2017)
- Grid Reserve Ordinance (NetzResV)
- Interruptible Loads Ordinance (AbLaV)

If a grid operator anticipates a grid congestion, it may firstly attempt to eliminate it with **grid-related measures,** adjusting the grid's topology by modifying the interconnection of grid sections in order to utilise the available grid infrastructure more effectively. Alternatively, the grid operator can make use of network components which control load flow such as phase-shifting transformers or (in future) high-voltage, direct current (HVDC) transmission lines. If grid congestion still remains following the grid-related measures, the grid operator still has market-related measures, additional reserves and adjustment measures at its disposal. The conditions under which the various measures may be implemented is governed by law.

- **Market-related measures (in particular redispatch and countertrading)**
  In order to eliminate impending grid congestion, grid operators can instruct power plants and storage units with a minimum nominal power of ten megawatts or more to adjust their operating schedules (dispatch). Such "**redispatching**" means that requested units must lower or raise their injection or extraction. The grid operator

20 Requesting here means starting up power plants which were scheduled to be idle. Grid reserve power plants are also always included. Starting up power plants requires notice to be given in good time (lead time).

remunerates the unit operator for the redispatch.[21] Redispatch therefore generates additional costs for the grid operator. TSOs may moreover curtail “interruptible loads” of major electricity consumers which are remunerated for voluntarily making their units available, *inter alia* for congestion management.[22] Little use is, however, made of “interruptible loads” for congestion management.

Another possibility is to counteract grid congestion by trading. TSOs can make use of the day-ahead and intraday markets to reduce physical transmission demand at critical points in the grid. This involves the TSO organising an offsetting transaction in which electricity is purchased “downstream of the congestion” and sold “upstream of the congestion”. Such transactions are in principle only capable of alleviating grid congestion between bidding zones or between control zones. This is because while the units participating in the day-ahead and intraday markets may indeed be assigned to a bidding zone and moreover, within Germany, to a control zone, the geographical assignment is no further subdivided. Such trading cannot eliminate grid congestion within a control zone. Where cross-zonal trades are involved, this practice is known as “**countertrading**”.[23]

- **Grid reserve dispatch**
  Grid reserve power plants are power plants which are solely used for redispatch purposes. TSOs can also contract foreign power plants as grid reserve power plants. Grid reserve power plants do not participate in the electricity market and are generally not at operational readiness. Long startup times to operational readiness mean that TSOs frequently have to request them in the course of initial measures. The TSOs can then instruct them to provide the required feed-in within a shorter lead time.

- **Feed-in management**
  If a grid congestion cannot be eliminated in any other way, grid operators can also curtail generation units which benefit from feed-in priority pursuant to the Renewable Energy Sources Act (EEG 2017) or the Combined Heat and Power Act (KWKG). Unit operators are compensated for this feed-in management on the basis of their lost revenues and the saved or additional expenditure due to the curtailment.

- **Adjustment measures**
  Grid operators are entitled and obliged to adjust all electricity feed-ins, transits and extractions in their control zones to the requirements of secure and reliable transmission grid operation. This is the case if potential or actual disruption of the security or reliability of the electricity supply system cannot be eliminated, or at least not in good time, by market-related measures or grid reserve dispatch.[24] Such adjustment measures are emergency measures for which no compensation is paid (except in the context of feed-in management).

  Figure 1 provides an overview of how unit operators, electricity traders and grid operators jointly ensure that generation and consumption are balanced at each point in time and that electricity can be transmitted from the generator to the consumer.

21 According to § 13a EnWG, the unit operator’s remuneration is allocated such that the operator is economically neither better nor worse off than in the absence of redispatch (EnWG 2020).

22 A provision of the Interruptible Loads Ordinance (AbLaV 2016).

23 See Article 2(27) Regulation (EU) on the internal market for electricity (Regulation (EU) 2019/943). In practice, however, this concept is also used for eliminating grid congestion between the four German control zones.

24 The grid operator deliberately removing certain loads from the grid is sometimes also known as a “brownout”.

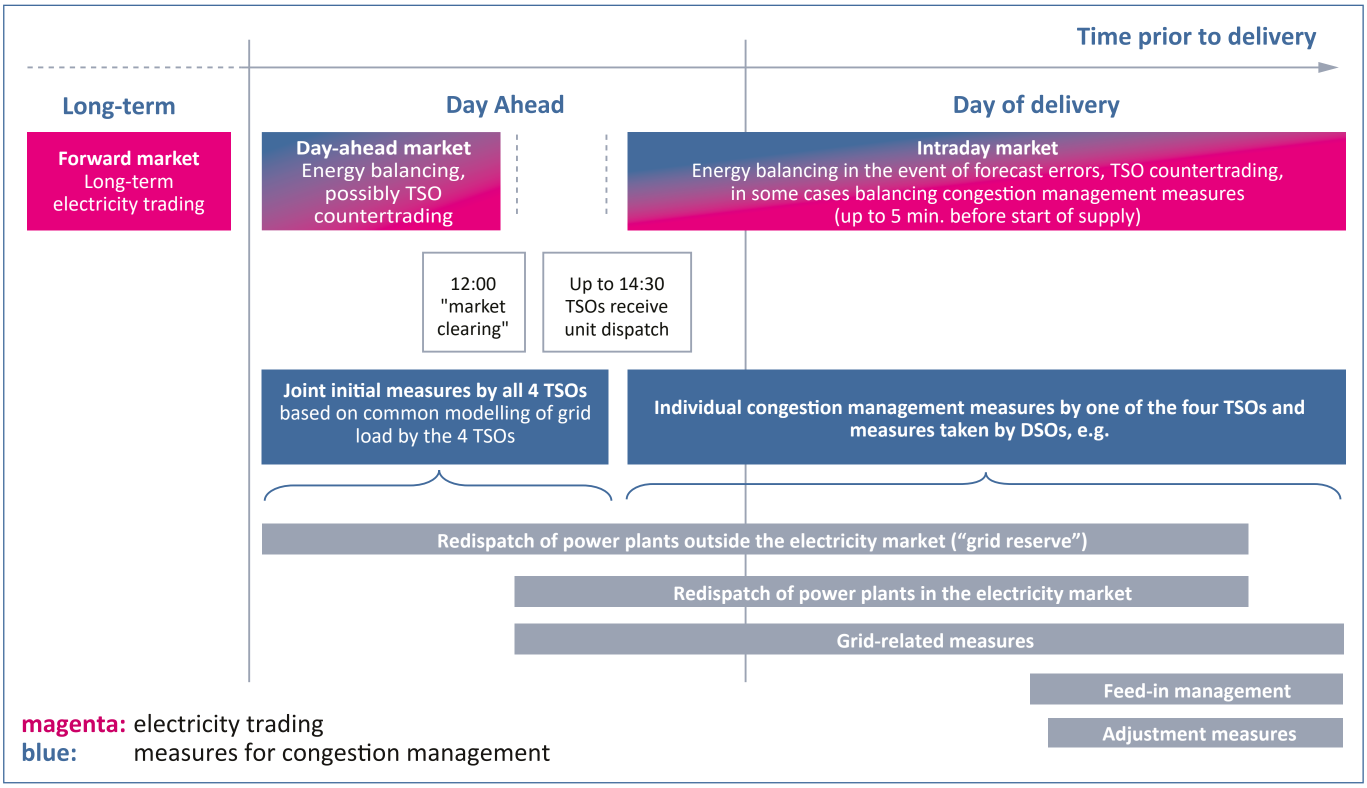

Figure 1: How flexibility is currently procured for congestion management

1.3 Fields of regulation

Measures for avoiding or eliminating grid congestion differ in respect both of the units involved and of the objectives pursued. Table 2 shows the possible measures divided into three different fields of regulation:

- Field of regulation 1: The grid operator can dispatch its own network components for congestion management.
- Field of regulation 2: Parameters for using third party generation, storage or consumption units can be set such that grid congestion is as far as possible avoided on the market at the dispatch stage.
- Field of regulation 3: If grid congestion is anticipated, the grid operator can use third party units to eliminate them.

		Units involved	
		Network components	**Third party generation, storage and consumption units**
Objectives of the measures	**Avoiding grid congestion**	**Field of regulation 1** Dispatch of network components by grid operator	**Field of regulation 2** Setting parameters, ensuring transmission capacity is taken into account during market dispatch of third party generation, storage and consumption units
	Eliminating grid congestion		**Field of regulation 3** Grid operator access to flexibility from third party generation, storage and consumption units, for example redispatch

Table 2: Fields of regulation for congestion management

1.3.1 Field of regulation 1: Use of network components

Grid operators can dispatch their own network components to pre-emptively prevent congestion (e.g. provision of reactive power to reduce the risk of voltage-related congestion). However, they can also dispatch their network components to eliminate specific instances of congestion (e.g. grid switching to relieve certain grid elements).

Unbundling

The aim of unbundling is to ensure a level playing field for competition for all market participants. Separating the information, accounting, company law and operational aspects of power grid operation from generation, storage, trading and distribution is intended to ensure grid operation independence and so prevent discrimination, cross-subsidies and other distortions of competition. If a grid operator is active simultaneously in all these areas, as was usual prior to power market liberalisation, it could for example disadvantage competing generators or suppliers in terms of grid access and so achieve a competitive advantage. In the course of the EU power market liberalisation which has been under way since the 1990s, grid operation has been increasingly unbundled from generation, storage and distribution. At the EU level, unbundling is prescribed by the Directive concerning common rules for the internal market in electricity and implemented in German law by the Energy Industry Act (EnWG). The unbundling regulations go further for transmission system operators than for distribution system operators. In addition, company law and operational aspects of unbundling do not apply to distribution grids with fewer than 100,000 connected customers. This means that in Germany around ninety per cent of power distribution system operators are exempt from comprehensive unbundling.

Competitive operation of power grids is ensured by the various energy regulators (Federal Network Agency (BNetzA) and state energy regulators). The role of the regulators includes monitoring whether all market participants are allowed non-discriminatory access to power grids, setting revenue caps for grid operators and approving grid development plans.

What network components a grid operator is allowed or obligated to keep available for congestion management is not laid down in detail in law. The fundamental objective is to separate state-regulated grid operation from the competitive fields of electricity generation, electricity trading and distribution and electricity storage (see box: Unbundling). Grid operators may therefore only operate units for generating and extracting electricity (including power plants, storage units, controllable loads) if necessary for electricity supply security. The conditions for this type of unit operation are narrowly defined. Fewer restrictions govern the operation of other technical units, for instance for providing reactive and short-circuit power. These units, for example flexible three-phase transmission systems or phase-shifter generators, are less likely to compete with the units owned by entities taking part in the competitive market.

The proposed policy options do not include changes to the provision and dispatch of network components.

1.3.2 Field of regulation 2: Dispatch of generation, storage and consumption units

The risk of grid congestion can be preemptively prevented or at least reduced. Achieving this means taking account of transmission capacity at the point where the decision is taken as to which generation, storage and consumption units are going to be dispatched. A market design is therefore needed which sets requirements or introduces incentives for controlling unit dispatch in such a way as to take account of transmission capacity. The current market design makes hardly any use of this option within the

German electricity bidding zone, with more detailed regulations still pending in some cases.[25] Only at bidding zone borders with neighbouring countries is limited transmission capacity taken into account in electricity trading.

Taking greater account of transmission capacity in dispatch decisions for generation, storage and consumption units could wholly or partly prevent grid congestion. Only instances of congestion which remains despite these measures would then have to be eliminated by dispatching network components or utilising flexibility. Given that grid congestion within the German electricity bidding zone is expected to persist or even increase, there would seem to be an urgent need for investigating if and how grid congestion can be avoided by dispatch-related measures . The three options "introduction of a nodal pricing system", "reconfiguration of the electricity bidding zone" and "introduction of utilisation-based grid fees" discussed in this position paper fall within this field of regulation.

1.3.3 Field of regulation 3: Flexibility dispatch for eliminating grid congestion

Grid congestion can arise if the dispatch of generation, storage and consumption units makes insufficient allowance for the grid situation. In this case, a grid operator needs to predict congestion and eliminate it using congestion management measures. If congestion cannot be eliminated by grid-related measures, a grid operator can intervene in the scheduled dispatch of generation, storage and consumption units. The approach to this may be market-based or non-market-based. A market-based approach involves operators of generation, storage and consumption units voluntarily offering flexibility by declaring themselves ready to operate their units in such a way as to relieve the grid (e.g. by feeding in more or less electricity from a power plant), with the grid operator choosing the offer which most favourably meets requirements. By taking a market-based approach, the grid operator procures flexibility for example on day-ahead or intraday markets on a countertrading basis.[26] In non-market-based procurement of flexibility, unit operators are required by law to provide flexibility, the relevant legislation stipulating the criteria by which unit operators are selected and remunerated.

In Germany, flexibility procurement for congestion management has previously mostly followed the non-market-based approach in terms of redispatch and feed-in management. However, since 1 January 2020 the regulation on the internal market in electricity[27] stipulates that flexibility has to procured in a market-based way in principle. Some exemptions do, however, remain under certain conditions. The new Directive concerning the internal market in electricity[28], set to be implemented by 31 December 2020, also stipulates market-based flexibility procurement for the distribution grid, but allows regulatory authorities to permit exemptions. German law currently continues to make significant provision for non-market-based procurement of flexibility.[29]

25 Possible approaches are suggested by § 19, paragraph 2, clause 1 StromNEV (Grid Fee Ordinance), which sets incentives for reducing grid use during periods of heavy load (StromNEV 2019), and in § 14a EnWG, which provides for a grid fee reduction if control of low-voltage consumer devices is handed over to the grid operator (EnWG 2020).

26 See above in 1.2.2 for countertrading which is becoming increasingly significant, in particular for eliminating grid congestion at the borders of the German bidding zone.

27 Regulation (EU) 2019/943, Article 13.

28 Directive (EU) 2019/944, Article 32.

29 Non-market-based redispatch pursuant to § 13a EnWG is to be further extended from 01.10.2021, see Article 13a EnWG as per Article 1(10) of Germany's 2019 Power Grid Expansion Acceleration Act.

It may be assumed that grid congestion will remain, even if transmission capacity is in future taken into account to a greater extent from dispatch onwards. Field of regulation 3 should therefore be considered irrespective of any further developments of field of regulation 2. The two options present in this position paper, “expansion of market-based procurement of flexibility” and “increased incentives for non-market-based procurement of flexibility” fall under this field of regulation.

2 Criteria for assessing policy options for congestion management

The objective of congestion management is to secure electricity supply despite limited transmission capacity. It prevents power cuts due to technical limitations. Achieving this requires grid congestion to be avoided or eliminated as far as possible. At the same time, consumers should be supplied even if not all the desired electricity trades can be executed due to congestion.

The following five criteria can be used to assess instruments for achieving this objective, in particular the options in terms of market design set out in section 3:

1. Effectiveness of congestion management
2. Short-term costs of congestion management and energy supply
3. Contribution to climate protection
4. Contribution to EU internal market in electricity
5. Feasibility and reasonable implementation costs

2.1 Effectiveness of congestion management

Options for action for improving market design in relation to congestion management have to be assessed for effectiveness, i.e. to what extent the objective of security of supply can be achieved despite limited transmission capacity. A crucial factor here is therefore to what extent consumers are supplied despite grid congestion. Current German congestion management is highly effective, with average power cut duration per grid-connected end consumer totalling only some twenty minutes annually over the last ten years. This is low when compared with the rest of Europe and internationally, but could be misleading: risks of a specific grid congestion requiring corrective action by grid operators have definitely often arisen. TSOs had to order redispatch measures due to grid overload on 354 days in 2018, for example.

As the energy transition progresses, there will probably be a further increase in total grid load and also changes in grid utilisation for which the grid is not designed. Added to this will be an expansion in international electricity trading in the context of the European Energy Union. Grid congestion is likely to occur frequently over the coming decades. Frequent critical grid situations resulting from the risk of grid congestion increase the risk of a grid operator failing to eliminate all instances of congestion by corrective action without impairing supply. It is therefore in principle advantageous to pre-emptively prevent the risk of grid congestion, so reducing the use of corrective measures by grid operators.

2.2 Short-term costs of congestion management and energy supply

The objective of securing supply despite limited transmission capacity needs to be achieved at the lowest possible cost. In this context, the present investigation considers the short-term costs (excluding capital costs) incurred on the one hand directly by congestion management measures (e.g. by managing bidding zone borders or redispatch), and on the other hand indirectly at another point in the energy supply system due to congestion management Such indirect costs arise for example in electricity trading as a result of higher electricity prices owing to reduced electricity market liquidity or poorer forecastability of costs. Climate protection costs are dealt with separately (see 2.3), as is market design transformation (see 2.5). The impacts of the measures discussed on decisions to invest in the grid or in generation, storage and consumption units and thus on the long-term congestion situation are not used as assessment criteria. The reason for this is that, on the one hand, the investigation focuses on operation of the electricity grid on the basis of existing units (see 1.1 above), while on the other hand consideration of the effects of the discussed policy options on investment decisions would yield an incomplete picture because this position paper does not investigate alternative options for action in terms of long-term congestion management (identification of grid expansion zones, surcharges and discounts when auctioning renewable energy generation capacity etc.).

The analysis assumes that it is to some extent efficient if not every consumer can be supplied at all times,[30] as this can lower congestion management and energy supply costs. For example, industrial companies might make interruptible loads available in return for remuneration, so offering to reduce their consumption in congestion situations. It is also possible to agree contractually on times for charging electric cars or for a grid operator to specify these. Market designs for congestion management need to be judged by how sucessful they are in keeping the overall costs for congestion management and energy supply as low as possible.

In 2019, the **costs incurred for congestion management measures** in the form of redispatch, countertrading, feed-in management and grid reserve power plants amounted overall to 1.2 billion euro, or approximately two per cent of total electricity supply costs (electricity grids and generation).[31] Taking the estimated electricity grid costs for 2017 as basis, congestion management costs would appear to make up around five per cent of these electricity grid costs.[32] As far as **electricity trading** within the German bidding zone is concerned, the current congestion management system largely minimises costs, since a congestion-free electricity grid is assumed and the most favourable offers across the whole country thus prevail on the electricity market.

30 The basic idea is that consumers should be supplied when the benefit of supply is higher than the costs, the consumers' willingness to pay being taken as an indication of the benefit gained.

31 The estimated total cost for power grids and conventional and renewable power generation amount to approximately sixty billion euro annually, see Fraunhofer ISI et al. 2017; BMWi 2019-1.

32 In 2017, the estimated total costs for all power grids amounted to approximately 24.1 billion euro, see Consentec/Fraunhofer ISI 2018-1.

2.3 Contribution to climate protection

The impacts of congestion management market design on greenhouse gas emissions and thus on climate protection need to be considered separately, especially given the ongoing intensive debate on climate policy. The costs for climate protection are therefore by definition not included in the above short-term costs for eliminating grid congestion.

The European Emissions Trading System ("EU ETS") internalises climate-related costs for the industrial and electricity generation sectors. However, its limitation to (primarily) these two sectors deprives the EU ETS of any significant steering effect when it comes to cross-sectoral use of electricity. This is true in particular of the heat and transport sectors, where electricity competes with other energy sources which are not subject to the EU ETS. The German Fuel Emissions Trading Act (BEHG)[33] provides for future national emissions trading in Germany in the heat and transport sectors, separately from but alongside the EU ETS. However, it is questionable whether this will result in sufficient coverage of climate-related costs and undistorted competition between energy sources.[34]

Against this background, the question arises as to whether the market design for congestion management should include further climate protection-related regulations, in addition to EU ETS and national emissions trading. At present, electricity from renewable sources, mine gas and high-efficiency combined heat and power generation has feed-in priority, and may consequently only be curtailed after conventional generation units (§ 14 para. 1, clause 1, no. 2 EEG 2017).[35] This does not contribute to climate protection, however, if such regulation merely leads to a redistribution of greenhouse gas emissions between the units involved, because the EU ETS merely sets an overall cap on permissible greenhouse gas emissions ("water bed effect"). Climate protection contributions within the purview of the EU ETS will therefore not be addressed in greater detail here. However, a further contribution to climate protection outside the scope of the EU ETS may be made by replacing more greenhouse gas intensive energy sources.[36] This effect is the focus of the criterion "contribution to climate protection".

2.4 Contribution to EU internal market in electricity

European Union law, being designed to strengthen the EU internal market in electricity, promotes cross-border electricity trading and cross-border use of flexibility. Consumers can thus benefit from more favourable electricity prices. In addition, a strengthening of the internal market in electricity can contribute to effective and inexpensive congestion management by incorporating units from neighbouring countries with lower costs or higher grid congestion sensitivity. Sufficient cross-border transmission capacity needs to be available if the internal market in electricity is to be expanded.

33 Fuel Emissions Trading Act (BEHG 2019).

34 The ESYS working group for power market design's second position paper (acatech/Leopoldina/Akademienunion 2020-2) addresses the issue of how to incorporate climate protection costs into market design. Please see this position paper for a more detailed discussion of this issue.

35 This feed-in priority will be slightly restricted and made more cost-oriented by the new version of § 13 EnWG, which will come into effect on 1 October 2021, but will persist in principle, see Power Grid Expansion Acceleration Act 2019.

36 This is also true of the heat and transport sectors, providing these are not subject to any upper limit for greenhouse gas emissions.

Simplification of cross-border electricity trading is closely associated with the extent of grid congestion within bidding zones. The more transmission capacity is provided at the bidding zone borders for cross-zonal electricity trading, the more the risk of grid congestion within bidding zones increases. This is why cross-zonal trading capacity has been strictly limited in the past. To strengthen the internal market in electricity, the EU Regulation on the internal market in electricity now provides for high minimum proportions of available transmission capacity at bidding zone borders – in principle seventy per cent by the end of 2025 – for cross-zonal electricity trading within the EU. This could well on the one hand lead to a significant increase in cross-border electricity trading, while on the other hand also aggravating congestion situations within Germany.

2.5 Feasibility and reasonable implementation costs

A change in market design for congestion management requires changes to the existing regulatory environment, any changes needing to be both legally and practically feasible. From a legal standpoint, contradictory Union and constitutional regulations are particularly problematic, as they are difficult to amend. In addition, practical difficulties may arise, for instance if desired changes require the agreement of specific market participants or run contrary to the interests of other EU Member States.

Furthermore, the effort involved in implementation, both for the companies affected and government agencies, needs to be in proportion to the advantages of the new market design. The risk of potential unforeseen undesirable effects also needs to be included in any assessment. As a rule, the more serious the changes made to the market design, the greater the effort involved in changeover. Therefore major changes should only be made if they promise correspondingly major advantages in respect of effectiveness, efficiency, climate protection and the internal energy market.

3 Options for Action

A total of five options for action with regard to further developing the market design for congestion management will be described below. The first three of these are intended to control dispatch decisions relating to generation, storage and consumption units in such a way that the risk of grid congestion is generally avoided (see field of regulation 2 above). The introduction of a nodal pricing system, a reconfiguration of the previously uniform German electricity bidding zone and the introduction of utilisation-based grid fees will be investigated.

Two further options for action relate to instruments for procuring flexibility for congestion management in cases where the risk of a specific congestion has already arisen (see field of regulation 3 above). These provide for the procurement of flexibility to take a more market-based approach and for greater incentives for flexibility provision where procurement is not market-based.

3.1 Introduction of a nodal pricing system

The basic idea behind a nodal pricing system is to calculate electricity prices separately for each grid node (i.e. for each injection point and each extraction point of the electricity grid).[37] When setting electricity prices for grid nodes, transmission capacity and optionally further parameters[38] are taken into account, in addition to nodal electricity supply and demand. Nodal prices indicate the marginal costs for additional extraction at the respective grid node taking account of transmission capacity.[39] If unlimited electricity exchange is possible between two nodes – i.e. there is no grid congestion between these two nodes – electricity prices at the nodes converge, whereas they differ if line capacity is insufficient.

Unlike in the current German system, there is no uniform wholesale electricity price for the entire system. Instead, in a nodal pricing system electricity prices are set by a central operator, for example an Independent System Operator (ISO), on the basis of an algorithm. Such an operator takes over at least some of the grid operator's tasks over all the grid nodes involved, in particular with regard to congestion management.

37 For nodal pricing system design see for example Monitoring Analytics 2019; Consentec/Neon 2018; Kunz et al. 2016; Neuhoff et al. 2013.

38 The US nodal pricing system also often takes account of grid losses, an example being the Midcontinent ISO (MISO), see Potomac Economics 2019-1; or alternatively the Electric Reliability Council of Texas (ERCOT), see Potomac Economics 2019-2.

39 See Potomac Economics 2019-1; Wolak 2011.

At several chronologically successive market stages, price setting is adjusted to the information available at each stage.[40] Figure 2 shows how wholesale electricity prices differ in a nodal pricing system and in a uniform bidding zone.

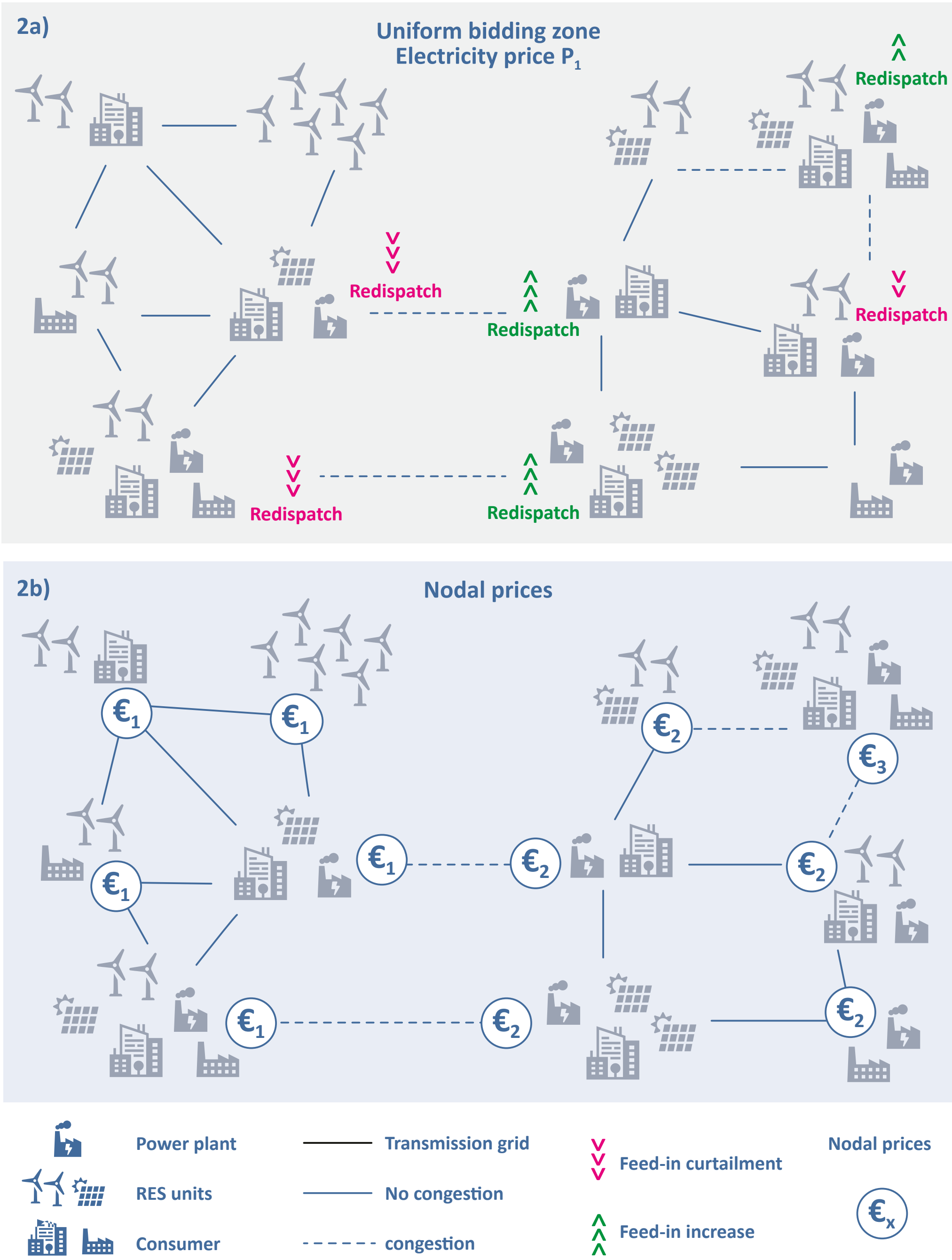

Figure 2: Illustration of electricity prices in a nodal pricing system in the transmission grid. Consumers, generators and grids are arranged in the same way in the top and bottom parts of the figure. Congestion in the transmission grid are depicted with dashed lines. In a uniform bidding zone (top), congestion management measures are needed to counteract congestion, such as increases and reductions in feed-in in the course of redispatch. A nodal pricing system does not involve these measures. If there is no congestion between a pair of nodal points, electricity can be exchanged without significant restrictions, and the prices at these nodes converge, whereas at nodes between which electricity cannot be transmitted without congestion, prices differ.

40 The current system also involves successive market stages, so as to allow short-term adjustments for example due to weather-related changes in feed-in from renewable energies. For instance, the day-ahead market is followed by the intraday market and, for very short-term adjustments by a grid operator, the balancing and reserve power markets.

3.1.1 Effectiveness of congestion management

- **Potential for very high effectiveness**
  If transmission capacity is taken fully into account when setting electricity prices, the risk of grid congestion can be largely ruled out from the outset. The continuing need for further measures to eliminate specific instances of grid congestion is thus very limited. A nodal pricing system is therefore a very effective measure for avoiding grid congestion. Furthermore, a central stakeholder has access at each market stage to nodal unit dispatch planning, making calculation of load flows more reliable than in the present system, which does not require market participants to inform the TSO of what units are to be dispatched to fulfil electricity supply contracts until 14:30 the preceding day.

- **Restricted effectiveness due to high complexity**
  The electricity grid consists of many individual grid nodes and comprehensively modelling all of them is a major technical challenge. If not all nodes are modelled, the effectiveness of this option is limited. Complex load flow calculations are needed for determining nodal prices. Ideally, the calculations for all the grid infrastructure are carried out on the basis of precise location and time information relating to all current injection and extraction operations. Parts of the USA, Russia, New Zealand, Australia and Singapore have experience with such a system. The nodal pricing systems established in these countries make it clear, however, just how challenging and complex implementation is. Nodal pricing is therefore generally only to be found at higher grid levels and also sometimes on a simplified basis. Due to the smaller number of grid nodes, nodal pricing systems are particularly suitable for transmission grids (extra-high voltage) and possibly high-voltage distribution grids. For medium- and low-voltage levels, the necessary load flow calculations cannot at present always be performed due to a lack of available information. It is questionable, particularly at the low-voltage level, whether it makes sense to provide the necessary metering instrumentation and to perform load flow calculations given the cost of such measures.

  Limiting the nodal pricing system to just the extra-high and perhaps the high-voltage grids, however, would be associated with disadvantages. As the energy transition progresses, the medium- and low-voltage grid levels are becoming ever more important for congestion management, as increasing volumes of electricity are fed into the lower grid levels (e.g. by wind energy and PV units) and extracted (e.g. for heat pumps or e-mobility) in decentralised manner. Partly, electricity is injected from lower voltage-level grids into higher voltage-level grids. These developments leads increasingly to grid congestion in the high- and extra-high voltage grids. Since it is often the case that no precise load flow calculations are available for lower grid levels, interactions between the grid levels are difficult to anticipate on a case-by-case basis. A nodal pricing system which only takes account of the extra-high and high-voltage grids cannot therefore reliably rule out the occurrence of grid congestion. This limits the effectiveness of such a nodal pricing system.

3.1.2 Short-term costs of congestion management and energy supply

- **Limited transmission capacity taken into account in electricity pricing**
  Electricity prices at grid nodes take account of the transmission capacity in the system. In the event of grid congestion it is thus possible for the generating unit

dispatched not to be the one with the lowest generation costs but rather the next most favourable unit which is suitable for supply purposes when transmission capacity is accounted for. Thus, providing generation costs and transmission capacity are correctly modelled, the generation units dispatched are those which are capable of meeting electricity demand at the overall lowest costs.[41]

- **Rapidly falling costs for flexibility, additional costs for nodal pricing system**
  In a nodal pricing system, flexibility costs are not incurred, to the extend at which transmission capacity is already taken into account during electricity price setting. Corrective action is therefore no longer necessary. At the same time, the flexibility which is no longer needed for congestion management can be used elsewhere, such as for balancing the system (e.g. it can be marketed as balancing and reserve power). In contrast, application of the nodal pricing system generates additional costs in comparison with the current zonal pricing system.

- **Possible additional costs for electricity trading due to market power, low liquidity and volatile prices**
  Nodal electricity price setting may result in very small regional markets due to limited transmission capacity. On such markets, individual sellers may occupy a very dominant position, i.e. have significant market power, which they could exploit to drive up prices on electricity markets, leading to inefficient electricity prices. To prevent this, the market needs to be appropriately monitored, the instruments needed for this possibly going beyond the general antitrust instruments used to control market power. Moreover, discontinuing the Germany-wide uniform wholesale electricity price has other effects on electricity trading: electricity market liquidity would be likely to drop while spot market prices would be likely to become more volatile. This could lead in particular to higher prices on the futures markets. Some market participants might also consider it important to protect themselves to an increased degree against severely fluctuating electricity prices. The result could be increased electricity trading costs compared with the current zonal pricing system.

- **Tighter regulatory control of the grid operation business needed**
  In a nodal pricing system, the earnings potential for market participants is heavily dependent on the configuration of the pricing rules as well as the decisions taken about the operation, maintenance and expansion of the grid. The entities responsible for this (central operator and possibly also grid operators) may have greater influence in a nodal pricing system than in the current zonal pricing system. Tighter regulatory control is therefore needed in a nodal pricing system to ensure that the grid operation businessis conducted in a non-discriminatory and transparent manner.

3.1.3 Contribution to climate protection

- **Use of climate-friendly generation units can be increased**
  A nodal pricing system introduces incentives for making cross-sectoral use of inexpensive electricity from renewable sources. This is because it results in low electricity prices at those grid nodes at which electricity extraction leads to the dispatch of inexpensive generation units which would not otherwise be used due to grid congestion.

41 See Monopolkommission 2015; Grimm et al. 2019.

3.1.4 Feasibility and implementation costs, contribution to EU internal market in electricity

- **Legal uncertainties and organisational hurdles**
  There is no clarity as to whether a nodal pricing system is legally compatible with the EU regulation on the internal market for electricity, since this in principle provides for a zonal pricing system.[42] Should this not be the case, the EU Council and Parliament would need the necessary majorities to amend the regulation.

  The introduction of a cross-grid nodal pricing system, which brings together different grid operators' grids, does come up against particular organisational challenges: were one central operator to take on the tasks of grid operation management, the grid operators involved would need to hand over some areas of responsibility. For a Germany-wide nodal pricing system with a central operator merely at transmission grid level, this would mean that the four TSOs Amprion, TenneT, TransnetBW and 50Hertz Transmission would have to come to an agreement. Expanding the nodal pricing system to at least some of the distribution grid level would mean the affected distribution system operators (DSOs) having to hand over some areas of responsibility for grid operation management to the central operator.

  The decisions taken by this central operator and possibly a grid operator alongside would have a direct impact on market participants' earnings potential, a fact which might well raise further reservations about handing over responsibilities. Given the above, cross-border introduction of a nodal pricing system appears to be particularly difficult to implement.

- **High implementation costs due to system change**
  Introduction of a nodal pricing system requires extensive changes to the system compared with the current zonal pricing system. The current Germany-wide electricity price setting system would have to be dropped and replaced with a new calculation algorithm. Market participants would have to adjust to this new price setting method and possibly conclude additional hedging transactions. This would be expensive for everyone involved.

3.1.5 Need for further research

The extent to which it is practical to transfer responsibilities from the existing grid operators to a central operator remains to be clarified. If the distribution grids are also going to be involved, technical feasibility and likely costs need to be investigated. With decentralised generation and consumption increasing, there is a need for an investigation into the extent to which a nodal pricing system limited to the extra-high and possibly high-voltage levels could in any way improve the effectiveness and efficiency of congestion management.

There is also a need for further investigation into market power, specifically the extent to which a nodal pricing system could lead to sellers having strong market power and so impeding electricity market operation.[43] Furthermore, the possible disadvantageous effects of a nodal pricing system on futures trading and any financial hedging

42 See Articles 14–17 Regulation (EU) on the internal market for electricity (Regulation (EU) 2019/943).

43 Analyses of US nodal pricing systems suggest that market power is a significant issue and active measures to limit it are therefore needed. To an extent, this is regarded as a given (see for example Potomac Economics 2019-1 and 2019-2), but some regulatory changes are also considered necessary (see for example Potomac Economics 2019-3; California ISO 2019).

costs need as far as possible to be quantified and weighed up against the advantages such as reduced flexibility costs. Given the significant scope of a changeover to a nodal pricing system, a detailed and ideally quantitative evaluation of the advantages and drawbacks is particularly important.

3.2 Reconfiguration of the German electricity bidding zone

Germany, together with Luxembourg, is currently a uniform electricity bidding zone with a uniform wholesale electricity price. Electricity trading within the bidding zone takes no account of the electricity grid's transmission capacity. When it comes to concluding trades, transmission capacity is accordingly assumed to be unlimited ("copper plate"). In fact, limited transmission capacity is not always capable of delivering electricity in the way provided by the trades. Grid operators frequently have to intervene in third party unit dispatch in order to eliminate grid congestion.

Reconfigured bidding zones make it possible to take transmission capacity into account already in the electricity trading stage. The bidding zone borders would in this case more closely reflect structural congestion[44] in the transmission grid. Instances of congestion are referred to as "structural", if it occurs repeatedly over an extended period of time that not all the desired electricity trades can be executed due to the limited transmission capacity.[45] In the light of limited transmission capacity between northern and southern Germany, discussions are under way in particular about splitting the German electricity bidding zone into northern and southern parts.[46] If a cross-zonal electricity trade were to be made, transmission rights for the cross-zonal lines would then have to be purchased in addition to the traded volumes of electricity. The Regulation on the internal market for electricity is prompting a review of bidding zone borders.

The underlying approach shares similarities with the introduction of nodal pricing. The focus on available transmission capacity is, however, less consistent since only the transmission grid and only its most significant ("structural") congestion is taken into account. Other grid levels and also all non-structural congestion in the transmission grid are ignored. Individual pricing is consequently not required at thousands of grid nodes, but only for the respective bidding zones and at the bidding zone borders. Limitations of transmission capacity within a bidding zone will, as in the past, not be taken into consideration during electricity trading. This has advantages for electricity trading, including higher market liquidity. In the light of these advantages, the less accurate modelling of transmission capacity limitation is accepted. Figure 3 illustrates splitting a territory into two bidding zones.

44 Pursuant to Art. 2(6) of the Regulation on the internal market for electricity, "structural congestion" means congestion in the transmission system that is capable of being unambiguously defined, is predictable, is geographically stable over time, and frequently reoccurs under normal electricity system conditions (Regulation (EU) 2019/943).

45 Insofar as existing bidding zone borders are not based on structural congestion, reconfiguration could also lead to bidding zones being extended.

46 See for instance Monopolkommission 2011; Egerer et al. 2015; Marjanovic et al. 2019. However, on the basis of an analysis of the four German TSOs, BMWi is working on the assumption that structural congestion would be distributed across the entire German transmission grid and would not mark out an unambiguous route for the course of a bidding zone, see BMWi 2019-2.

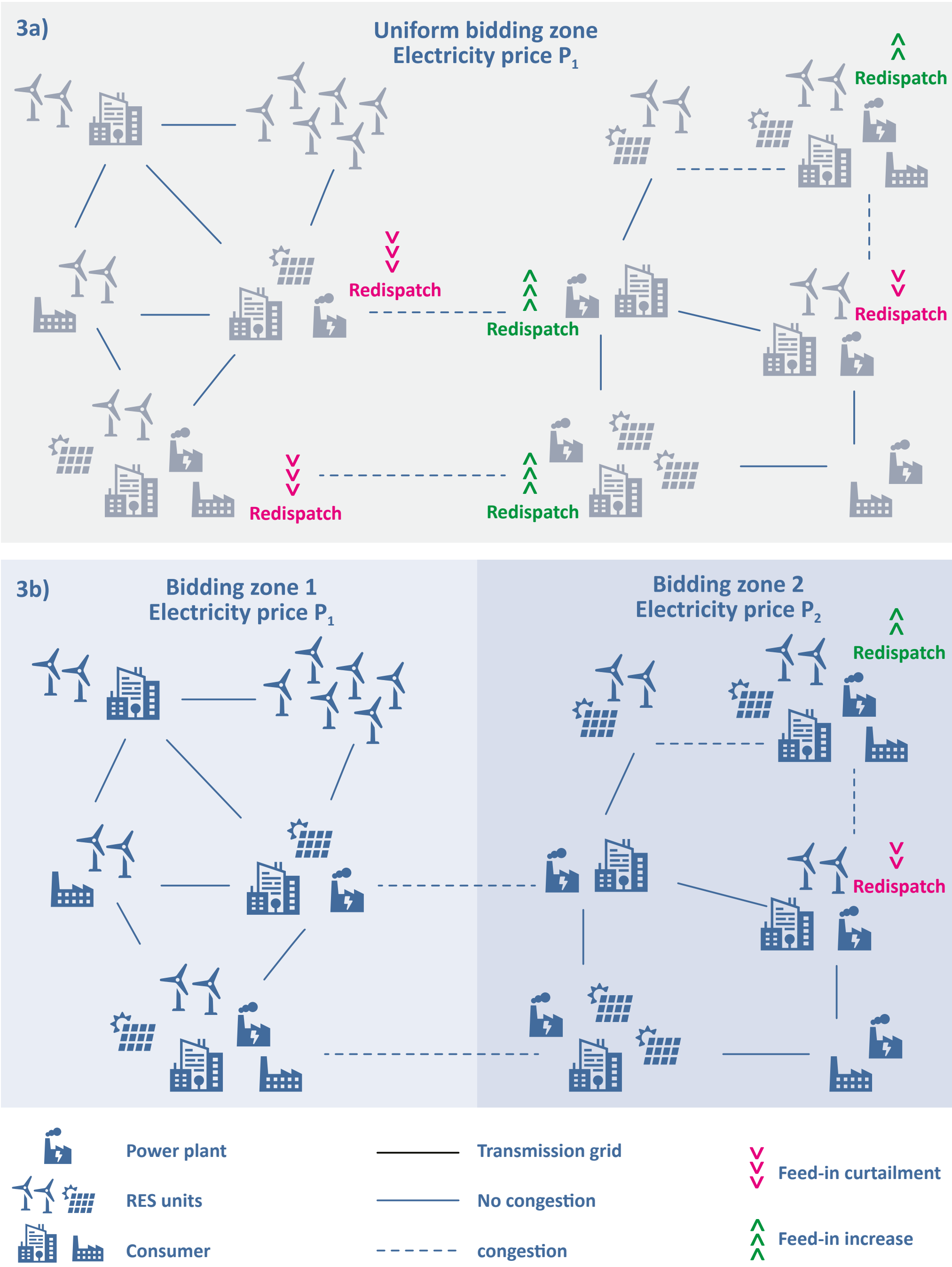

Figure 3: Illustration of splitting a wholesale electricity market bidding zone in two. The same arrangement of consumers, generators and grids is shown by way of example in the top and bottom parts. Congestion in the transmission grid is depicted with dashed lines. In a uniform bidding zone (top), there is a uniform price on the wholesale electricity market and congestion management measures are needed to counteract congestion, such as increases and reductions in feed-in for the purpose of redispatch. In order to take account of structural congestion, the bidding zone can be split into two bidding zones, each with its own wholesale electricity price (bottom). No congestion management measures are any longer required between the two bidding zones. Congestion does, however, still remain within a bidding zone which grid operators will still have to counteract by congestion management measures.

3.2.1 Effectiveness of congestion management

- **Corrective grid operator interventions are reduced**
  Reconfiguring the bidding zones contributes to more effective congestion management if the necessary corrective grid operator interventions, in particular for procuring flexibility, can be reduced as a result. The better the new bidding zone borders model the structural congestion in the transmission grid, the greater are the advantages for effectiveness. In contrast, a bidding zone reconfiguration takes account neither of grid congestion which is non-structural in nature and hence does not occur for an extended duration or repeatedly nor indeed of distribution grid congestion.

- **Structural congestion displacement may limit effectiveness**
  Advantages in terms of the effectiveness of congestion management are obtained if the bidding zone is configured to model the structural congestion. Displacement of grid congestion due to changes in grid utilisation degrades the effectiveness of congestion management. Regular review and, possibly, adjustment of bidding zone borders would therefore be required to maintain effectiveness.

3.2.2 Short-term costs of congestion management and energy supply

- **Auction of transmission capacity at the bidding zone borders takes account of consumer benefits**
  As early as the conclusion of cross-zonal electricity trades, the market can determine consumers' willingness to pay by auctioning cross-zonal transmission capacity. This is in principle an efficient way of taking account of consumer benefit. Potential cost benefits are obtained in comparison with the current two-stage approach (electricity trading first, followed by congestion management).

  There is, however, some latitude in the decision how much transmission capacity should be available for electricity trading. The extent to which account should be taken of the additional possibility of cross-zonal redispatch or countertrading must also be decided.[47] These decisions have a considerable impact on the costs for using cross-zonal transmission capacity and on the efficiency of bidding zone configuration.

- **Falling flexibility costs, additional costs for managing bidding zone borders**
  Grid congestion management costs fall since grid operators have to intervene more rarely. At the bidding zone borders, there is no need for corrective action as far as the available transmission capacity has already been taken into account during electricity trading. At the same time, the flexibility no longer needed for congestion management can be used for other purposes such as balancing the system. These effects must be set against the costs for managing the bidding zone borders. These costs arise even at times of day or seasons when congestion is absent and congestion management would accordingly not be necessary.

- **Potentially higher costs for electricity trading due to reduced liquidity**
  It is in principle to be expected that splitting Germany's electricity bidding zone will lead to higher electricity trading costs and thus higher wholesale electricity prices. This is also the lesson learned from splitting bidding zones in Sweden in 2011 and splitting the German-Austrian bidding zone on 1 October 2018.[48]

47 The current regulation is set out in Art. 16 of the Regulation on the internal market for electricity.

48 See EFET 2016. The announcement of the splitting of the Germany–Austria bidding zone and product transition from Phelix DE/AT to Phelix DE over 2017-2018 led according to EEX to additional costs in excess of 700 million euro due to an increased bid-ask spread.

However, various effects have to be taken into account. One aspect is that an increase in the wholesale electricity price can in particular be expected for southern Germany, where low-cost generation units are frequently physically incapable of meeting demand. Higher wholesale prices in southern Germany are the result of the reduced supply and the limited possibility for creating portfolios within the smaller bidding zone c. In contrast, wholesale electricity prices may be lower in northern Germany.

For a comprehensive assessment, it must be borne in mind that costs previously attributed to grid operator congestion management, for example for redispatch at a structural north-south congestion, can then no longer be covered by grid fees and thereby be allocated outside of the electricity trading. This suggests a rise in electricity trading costs. However, at the same time, redispatch costs fall, thus another fraction of the overall energy supply costs is decreased.

In addition, splitting the German electricity bidding zone could possibly make more cross-zonal transmission capacity available to neighbouring countries and thus reduce wholesale prices on the electricity markets (see below, in relationto the contribution to the EU internal market in electricity). However, EU law in any event stipulates that by the end of 2025, seventy per cent of the transmission capacity has to be made available for cross-border electricity trading.

- **Adjustments to bidding zone borders reduce planning certainty**
  The bidding zone reconfiguration considered here is directed towards structural congestion. The bidding zone border should consequently be regularly reviewed and possibly adjusted. More frequent adjustment does, however, complicate long-term prediction of electricity prices and transmission costs. As a result, the futures market in particular may function less well due to reduced planning reliability for electricity consumers and generators.

3.2.3 Contribution to EU internal market in electricity

- **Getting away from national borders**
  Zonal pricing systems are highly compatible with the aim of an EU internal market in electricity because zones can in principle be defined on the basis of structural congestion independently of national borders and without distinguishing between Member States. For example, it could also be possible to create bidding zones comprising parts of a number of countries providing that there is no structural congestion at the national borders.

- **Lower pressure to limit transmission capacity at bidding zone borders with neighbouring countries**
  Splitting bidding zones to reflect structural congestion within a country can help to increase the transmission capacity available for electricity trading at the bidding zone borders with neighbouring countries. At present, grid operators within Germany frequently have considerable congestion management work to do. Electricity imports may make existing congestion situations more acute. For example, importing electricity from Scandinavia for delivery to southern Germany places an additional load on the power lines between northern and southern Germany. Indeed, some of the lines are already overloaded by the transmission of wind-generated electricity from northern Germany to the industrial regions in the south of the country. In order to avoid additional grid congestion and the associated costs, grid operators therefore sometimes limit the line capacity for cross-border electricity trading which they make

available at the bidding zone borders with neighbouring countries. If Germany were now to be split into two bidding zones to reflect structural congestion between northern and southern Germany, both north German and Scandinavian electricity suppliers would have to purchase transmission rights for the new bidding zone border. The electricity suppliers would compete on the market for the limited transmission capacity from northern to southern Germany. As a result, it would be ensured from the outset that sufficient line capacity is available for permitted cross-zonal trades.[49] Grid operators would therefore no longer have any reason to limit electricity import capacity in order to cut redispatch costs. At the same time, additional competition between German and foreign sellers could reduce energy supply costs.

The EU Regulation on the internal market for electricity does, however, in any event stipulate an increase in cross-border transmission capacity for electricity trading to seventy per cent by the end of 2025. Against this background, splitting the German bidding zone could possibly help to reduce costs if, as a result of the management of the bidding zone border within Germany, there is a fall in demand for cross-border transmission capacity and thus in the need for cross-border redispatch.

3.2.4 Contribution to climate protection

- **Use of climate-friendly generation units can be increased**
  Reconfiguration, in particular splitting, of the German bidding zone may, in the event of grid congestion at the bidding zone borders, lead to lower electricity costs in those parts of Germany in which low-cost generating capacity availability is higher than consumption. This creates an incentive not to curtail electricity from renewable energies but instead to put it to use cross-sectorally.

3.2.5 Feasibility and implementation costs

- **Complex and politically difficult**
  A reconfiguration of the German bidding zone generates considerable cost for electricity trading, even if the zonal pricing system is retained. In particular, long-term electricity supply contracts have to be adjusted. Furthermore, congestion management within bidding zones has to be adapted to the new territorial configuration, because grid congestion at the new bidding zone borders is now managed by auctions. In addition, various electricity price components which have previously been set Germany-wide, such as the renewable energy and combined heat and power surcharges pursuant to EEG and KWKG and the transmission grid fees[50], would have to be reviewed because it may no longer be appropriate to determine them uniformly over separate bidding zones. In addition, economic and social policy reservations in relation to differing electricity prices across Germany must be taken into account.[51]

3.2.6 Need for further research

The criteria for structural congestion should be more precisely defined. There is a need for more detailed investigation into possible bidding zone borders to determine how far the congestion is of a structural nature and how far it may still vary by time of day or seasonally. The cost effects on electricity trading of reconfiguring and in particular

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49 This measure, like all the options for action set out in this document, does not increase the physical transmission capacity of the grid. It does, however, reduce the need for corrective action by grid operators, since only limited transmission capacity for trading is provided from the outset.

50 See §§ 24 and 24a EnWG and §§ 14a ff., 32a Grid Fee Ordinance (StromNEV 2019): progressive standardisation of transmission grid fees since 1 January 2019 with the target of uniform transmission grid fees from 2023.

51 Grid fees, with the exception of transmission grid fees, will however in any event be calculated at grid level and may therefore differ considerably across Germany.

reducing the size of bidding zones should as far as possible be quantified. These costs need to be compared with the cost effects in the event of congestion management within bidding zones. This is particularly the case for possible cost savings in the event of a bidding zone being split. Forecasts of electricity price trends in bidding zones should also be undertaken in this context. Furthermore, any consequential changes in the determination of grid fees and the surcharges which have previously been uniform throughout Germany should be analysed. Finally, a more detailed investigation is required into the time intervals being considered for a possible reconfiguration of bidding zones and how the resultant advantages and drawbacks are to be evaluated.

3.3 Introduction of utilisation-based grid fees

The grid tariffs for using electricity grids could be reconfigured to charge a higher grid fee in the case of critical grid utilisation than in other cases, thereby providing an incentive to adapt grid usage to current and voltage limit values and reducing the risk of grid congestion. As grid fees are payable on top of the electricity price and other electricity price components (taxes, duties, surcharges), utilisation-based grid fees may also have a place in a zonal pricing system. In addition to a new, utilisation-dependent component, grid fees would also include a utilisation-independent component, covering, for example, the costs of maintaining grid connections and grid usage billing.

The policy option addressed here, “utilisation-based grid fees”, needs to meet three criteria:

- Firstly, total grid fee revenue should cover total grid costs.
- Secondly, congestion management costs should be transferred to the grid users who use the grid when there is a risk of congestion. Therefore, the revenues from the utilisation-dependent grid fee component should cover the overall to congestion management costs.
- Thirdly, the utilisation-dependent grid fee component for individual grid users should reflect the proportion of congestion management costs apportionable to them.

This option does not completely rule out the risk of grid congestion, as these are probably not entirely predictable. Moreover, it must be assumed that congestion management costs, the grid users affected and the proportion of congestion management costs to be apportioned to them can only be approximately determined.

Ideally, the criteria used to determine utilisation-based grid fees should be sufficiently finely tuned in terms of geography and time to reflect both the location of grid congestion and its occurrence over a year or over a day. In concrete terms, however, a balance has to be struck between maximally precise modelling of the grid situation and feasibility of implementation. For example, broader geographic differentiation could be dispensed with within smaller distribution grids. At the low-voltage level, moreover, there is doubt as to whether the cost (e.g. for new metering instrumentation) can be justified. In addition, in particular at lower grid levels, not all grids are equally affected by grid congestion and therefore utilisation-based grid fees should not be applied to all grids. It also needs to be decided whether it is best to use grid utilisation forecast before the event or actual grid utilisation determined after the event as the basis for calculating grid fees.

A steering effect is only produced by utilisation-based grid fees applied to grid users who are liable for grid fees and who can change the amount of grid fees they pay by modifying their behaviour. As the system currently stands, these two criteria apply only to some grid users:

- On the one hand, **small customers** are billed according to a standard load profile, meaning that their grid usage behaviour does not have any affect on the amount they pay in grid fees. However, if power or load-profile metering were built in and the balancing method adjusted, grid fees could also be calculated on the basis of actual measured values.

- On the other hand, it is only **electricity consumers**, not **electricity feed-in suppliers,** which are currently liable for grid fees. Depending on configuration, however, consumer-side utilisation-based grid fees can also reflect whether the corresponding feed-in causes congestion. A congestion-relieving steering effect on feed-in could thus also be achieved. The specific configuration has not been investigated in any greater detail, however. A system of utilisation-based grid fees would be simple to implement if feed-in were to become liable for grid fees in addition to extraction. This approach would be particularly relevant when exporting electricity: if only consumers pay grid fees, there would be no incentive for providers of electricity across national borders to reduce load on the electricity grid.

3.3.1 Effectiveness of congestion management

- **Corrective grid operator interventions are reduced**

  Utilisation-based grid fees increase the cost of grid use at times of heavy grid utilisation. If the grid fee is high enough to restrict grid usage, the risk of grid congestion is reduced. This is advantageous for the effectiveness of congestion management as grid operators then have to take less frequent corrective action.

  However, the effectiveness of this option depends on various factors:

  - One critical factor is how much the grid fees are differentiated in accordance with **congestion regions** and **times** and which grids are included.
  - For grid fees to provide a sufficient incentive, additional measures are needed in the form for example of **adjustments** to the requirements for metering devices, metering and measured value transmission and to the balancing system (for instance by restricting the use of standard load profiles).
  - Furthermore, to avoid grid congestion caused by feed-in, **a steering effect on feed-in is also needed**. This might possibly require the introduction of grid fees on feed-in. With fluctuating electricity generation from renewable energy sources rising over the course of the energy transition, feed-in-related congestion is also expected to increase in frequency.

- **Scope of the steering effect**
  The utilisation-dependent grid fee component merely models congestion management costs, which limits the steering effect of utilisation-based grid fees. The steering effect depends on how high the additional costs would be if congestion were to occur. Given that one of the requirements in this respect is that the overall level of the utilisation-dependent grid fee components is determined by the congestion management costs, one critical factor is the volume of electricity over which these costs are spread. The smaller the volume of electricity, the greater the effect. It is therefore essential to establish what proportion of the electricity volume liable to grid fees is transmitted in critical grid situations. The box entitled "Impact of utilisation-based grid fee setting" provides some guidance in this respect.

  The impact of the signal sent by the grid fee may be diminished by the additional fixed electricity price components (e.g. municipal fee, EEG surcharge, electricity tax), as these reduce the relative significance of the grid fees for the electricity consumer. The above-mentioned fixed electricity price components differ widely for various groups of consumers: for domestic customers the fixed components make up over fifty per cent of the electricity price, while for larger consumers the proportion is markedly lower due to various exceptions which apply.[52] The higher the fixed electricity price components, the lower the relative significance of variable price components. Nevertheless, their absolute value can have a considerable steering effect.

Impact of utilisation-based grid fee allocation

To provide a general picture of the possible steering effect of utilisation-based grid fees, the possible increases in grid fees based on various assumptions relating to electricity volumes affected by grid congestion are presented here.

Congestion management costs for 2017[53] totalled 1.5 billion euro.[54] The estimated total costs of all grids amounted to 24.1 billion euro in 2017.[55] Consequently, congestion management costs made up 6.2 per cent of total grid costs.

Short-term **utilisation-independent** grid costs thus amounted to 22.6 billion euro, a value obtained from the total grid costs of 24.1 billion euro minus congestion management costs amounting to 1.5 billion euro. Spreading utilisation-independent grid costs evenly over all grid users gives a rough average grid fee of 4.35 cent per kilowatt-hour (22.6 billion euro divided by annual net electricity consumption of 520 terawatt-hours[56]) . The remaining **utilisation-dependent** grid costs reflect congestion management costs amounting to 1.5 billion euro, and would only be charged for grid use in congestion situations.

The effect on grid fees depends on the volume of electricity involved. As a guide, the utilisation-dependent proportion of grid fees can be determined for volumes of five per cent, ten per cent and 15 per cent of net electricity consumption with uniformly spread utilisation-dependent grid costs. Table 3 shows that the utilisation-based proportions of grid fees rise considerably in congestion situations and could therefore have a steering effect.

von Netzengpässen betroffene Strommenge	zusätzliches Netzentgeld in Engpasssituationen	Netzentgeldsteigerung in Engpasssituationen
5 % (26 TWh)	5,77 ct/kWh	133 %
10 % (52 TWh)	2,89 ct/kWh	66 %
15 % (78 TWH)	1,92 ct/kWh	44 %

Table 3: Example calculation showing increases in grid fees in congestion situations

52 See BNetzA/BKartA 2020, p. 282 ff.
53 2017 was selected because of total grid cost data availability.
54 BNetzA/BKartA 2019.
55 Consentec/Fraunhofer ISI 2018-1.
56 BMWi 2019-3.

On the other hand, the offsetting effects of low electricity prices can limit the effectiveness of the signal sent by grid fees in congestion situations, despite making sense economically. These effects arise for example if a high feed-in from renewable energies grid causes congestion and at the same time results in a major fall in wholesale electricity prices.

Major corrective interventions by grid operators in unit dispatch may therefore continue to be needed. Conversely it cannot be ruled out that utilisation-dependent grid fees have a prohibitive effect, when congestion management costs are spread over a comparatively small volume of electricity.

3.3.2 Short-term costs of congestion management and energy supply

- **Limited transmission capacity taken into account in the electricity price**
  If the costs of congestion management are reflected with sufficient accuracy by utilisation-based grid fees, electricity price and grid fees should in total reflect the provision costs. This would result in all electricity deliveries carried out for which consumer willingness to pay is higher than the total cost of the production of the electricity and its transmission to the consumer. This includes the congestion management costs respectively apportionable to the consumer, and leads in principle to efficient congestion management.

  However, determining the costs of congestion management is very difficult, especially if indirect costs (primarily for electricity trading) are to be included. In addition, apportioning the costs of congestion management to specific grid users is a very inexact science, which impedes the steering effect of grid fees.

- **Potential of falling costs for flexibility, additional costs for grid fee calculation**
  If higher grid fees result in lower volumes of electricity being delivered when there is a risk of grid congestion, grid operators more rarely need to take corrective action, and the amount of flexibility needed falls accordingly. At the same time, the flexibility no longer needed for congestion management can be used for other purposes such as balancing the system. The resultant cost benefits can be set against the costs incurred by the potentially complex process of determining utilisation-based grid fees.

- **Possible cost increases due to uncertainty about grid fee levels**
  One drawback of utilisation-based grid fees is that grid congestion is not entirely predictable, nor is long-term forecasting possible. To model grid utilisation reliably, shorter-term grid fee determination would be needed than hitherto (they are currently calculated a calendar year in advance) or even in arrears, meaning that they would still be unknown at the date of conclusion of large numbers of electricity supply contracts. Electricity prices for integrated supply contracts (i.e. contracts inclusive of grid fees) would therefore be more difficult to calculate, which might lead to cost increases for consumers.

  Additional costs would also be incurred for the necessary forecasts, with grid fee calculation complexity on the one hand being increased for grid operators if these fees need to be set in advance, requiring operators to estimate grid congestion and the costs of managing it beforehand. On the other hand, increased costs could also be incurred for distributors and optionally consumers if they want to predict grid fees before the grid operators publish them. This would in particular be the case if grid fees are only set in arrears. To safeguard against uncertainty about grid fee levels, futures market products could be used, but these entail further costs.

3.3.3 Contribution to climate protection

- **Use of climate-friendly generation units can be increased**
  Compared with the current situation, utilisation-based grid fees relieve those electricity supply situations which are not associated with any risk of grid congestion. A reduction in grid fees creates an incentive to dispatch electricity from renewable sources cross-sectorally in such situations, instead of curtailing it.

3.3.4 Feasibility and implementation costs

- **High implementation costs**
  The introduction of utilisation-based grid fees would entail considerable implementation costs, as a result both of changes to the grid fee system and billing procedures and of the installation of necessary information and communication technologies. However, if grid fees were to be reconfigured to align them more closely with usage in any case,[57] utilisation-based grid fees could be readily integrated into these considerations.

3.3.5 Need for further research

Utilisation-based grid fees are still in their infancy, with the UK's triad system providing the first practical experience.[58] The first step towards developing such a system is to draw up a specific implementation concept and so enable a clear assessment. There is still a major need for research in this respect.[59] Previous work has tended to focus on location-related investment signals, i.e. long-term congestion management[60], whereas in this case congestion management is investigated on the basis of the available plant fleet.

The possible steering effect of utilisation-based grid fees would need to be investigated in greater detail and quantified where possible. This concerns, on the hand, the extent of the utilisation-based grid fee component. On the other hand, it has to be analyzed how such an increase in grid fees influences grid user behaviour in interaction with the electricity price signal and the other electricity price components. The introduction of utilisation-based grid fees would only be justified if a significant steering effect were likely. Conversely, grid fees must not be allowed to have a prohibitive effect.

How utilisation-based grid fees can be set with sufficient accuracy also merits detailed investigation, as do the advantages and drawbacks of short-term advance fee setting as opposed to setting in arrears. The effects of utilisation-based grid fee design on electricity sales, for example owing to grid fees being unknown when a deal is concluded, must also be quantified.

57 See BMWi 2017; Consentec/Fraunhofer ISI 2018-2.

58 See Weyer/Müsgens 2020, p. 53.

59 Consentec/Fraunhofer ISI 2018-2 and dena 2019 are very reticent about a grid fee component for covering the costs of operational congestion management due to the difficulties involved in setting appropriate parameters.

60 See for example Grimm et al. 2019; Consentec/Fraunhofer ISI 2018-2.

3.4 Expansion of market-based procurement of flexibility for congestion management

If a grid operator is not able to relieve a grid congestion by calling on their own resources, they can fall back on third-party units (generation, storage and consumption units) in order to procure the necessary flexibility. Such an approach may be market-based, i.e. based on voluntary offers from flexibility providers, or non-market-based, in which case unit operators are required by law to provide flexibility.

The EU's new provisions under the Clean Energy Package (Regulation (EU) on the internal market for electricity and Directive concerning the internal market in electricity) specify market-based procurement of flexibility as the basis for eliminating congestion. German law also provides for market-based procurement, but barely any use has been made of this possibility, German unit operators instead largely being obliged by law to provide flexibility in return for reimbursement of costs.[61] Flexibility procurement in Germany is thus currently **predominantly not market-based**.[62]

If procurement of flexibility for congestion management is in future to adopt more of a market-based approach, regional flexibility markets may need to be set up. These would have to be designed such that the participating units are suitable for eliminating specific instances of grid congestion. For example, to relieve grid infrastructure in the case of feed-in-related grid congestion, units upstream of the congestion would have to reduce their feed-in or increase their extraction. On such markets, grid operators can take on the role of buyers, purchasing from the technical options offered (generation, storage and consumption units) the right to use flexibility. There is considerable latitude for configuring these markets in terms of organisational form and products. One organisational option is for example platforms which enable supply and demand transparency and bring the two sides together in accordance with market principles.[63] Where products are concerned, regulations need to be adopted with regard to specifications for the required reliability and for which timeframe flexibility must be made available.

3.4.1 Effectiveness of congestion management

- **Additional flexibility potential is tapped**
  Market-based flexibility procurement lead to an increased supply of flexibility. It encourages the disclosure and use of existing flexibility potential and the tapping of additional flexibility potential. In particular, it allows the **incorporation of loads** which have previously remained largely unused for congestion management purposes: statutory cost-based redispatch and feed-in management essentially merely oblige operators of generation units to adjust electricity feed-in and so provide flexibility, while load operators are not obliged to do so. Operators of electricity storage units are an exception. At the same time, flexible load potential is growing, not least because of the increased number of technical load control options.

61 Redispatch pursuant to § 13a EnWG 2020; feed-in management pursuant to §§ 14, 15 EEG 2017.

62 Market-based procurement of flexibility for congestion management is currently being trialled in demonstration projects as part of the "Smart Energy Showcase - Digital Agenda for the Energy Transition" (SINTEG) programme, see https://www.sinteg.de/.

63 The SINTEG "enera" project sets up regional flexibility markets with participation by EPEX Spot on the basis of the German spot market.

The current impossibility of load control by grid operators is due not least to the sometimes serious impact on the economic activity of businesses affected or the living conditions of private consumers. Such load-side restrictions run contrary to the objective of security of supply. Furthermore, it is much more difficult to calculate cost-based remuneration for loads than for generation units, since individual loads differ widely in terms of type and purpose and costs may fluctuate over time. These problems would not arise in the case of market-based procurement, since the relevant consumers are voluntarily selling flexibility on the market, at a price which they set themselves.

However, market-based procurement of flexibility is subject to restrictions, above all at low-voltage level, where there is uncertainty as to whether a relevant steering effect can be expected (e.g. due to the low cost impact) and whether the necessary expenditure (e.g. for new metering instrumentation) is justified.

- **Market-based and mandatory provision of flexibility can be complementary**
  Market-based procurement does not rule out the use of supplementary non-market-based instruments (e.g. redispatch or feed-in management). For instance, a grid operator may be allowed by law to require third parties to make their units available if market-based procurement is not feasible (e.g. due to low levels of competition and therefore inflated prices) or the flexibility voluntarily offered for sale on the market is insufficient to relieve grid congestion.

3.4.2 Short-term costs of congestion management and energy supply

- **Broader offer basis for flexibility can lower costs**
  The broader supply basis for flexibility may result in lower costs. For instance, the additional flexibility offered may lead to more favourable procurement prices. In addition, units tapped for congestion management purposes may be those which are more sensitive to a particular instance of grid congestion due to their location and thus also reduce demand for flexibility. Moreover, the newly tapped flexibility potential may reduce grid reserve requirements. On the negative side, tapping and using the additional flexibility may add extra cost, for example for metering devices, communication and handling.[64]

- **Risk of higher costs due to market power and inc-dec gaming**
  Only those flexibility options which are in the right geographical location can be used to eliminate a particular grid congestion. The volume of flexibility offered and the number of sellers are consequently often low, meaning that individual sellers gain market power and demand inflated prices. Market-based procurement may therefore require regulatory protection against inflated prices (e.g. in the form of price capping) or the whole idea of market-based procurement may have to be abandoned. Although market power can arise at all grid levels, the frequent lack of competition at the low-voltage level means that the risk is particularly high there.[65]

  "Inc-dec gaming" is another conceivable option. This involves market participants increasing or decreasing their bids on the spot market in order to maximise their

64 See also Frontier Economics 2017.

65 Alternative flexibility procurement instruments (in particular on the load side) should consequently be considered. The legal approach taken in § 14a EnWG for example provides for control of the power drawn by grid operators in return for a reduction in grid fees (EnWG 2020). Various proposals are being discussed with a view to further development, see for instance Döring et al. 2019; EY et al. 2019; BMWi 2019-2.

returns by offsetting on the flexibility market[66]: due to the geographical requirements of congestion management, higher price margins can be achieved on the flexibility market than on the spot market. In inc-dec gaming, flexibility providers withhold their offers on the spot market in the hope of achieving a higher price on the flexibility market. This creates problems as withholding offers can result in price increases on the spot market, and the demand for and costs of calling flexibility may also rise.[67] The extent to which such market behaviour is macroeconomically inefficient is questionable, however, if market participants merely want to achieve the appropriate market price for their electricity taking account of its suitability for congestion management.

Inc-Dec Gaming

If flexibility for congestion management is procured using a market-based approach, sellers of flexibility can decide whether to offer it for sale on the power market (spot market) or on a regional flexibility market for congestion management. If market participants are able to anticipate congestion and higher returns are to be expected on the flexibility market than on the spot market, then participant bidding behaviour can make congestion worse. An example would be where the next day's forecast is for strong winds in northern Germany. A supplier in Schleswig-Holstein in northern Germany with a smart charging algorithm for electric cars or electric heating systems would then hold back from buying any electricity on the spot market the day before, but instead would wait to obtain more inexpensive electricity by taking part in the flexibility market. A supplier with a similar smart charging algorithm located in southern Germany, on the other hand, indicates heavy power demand on the spot market, so as then to be able to redispatch this (hypothetical) demand and be reimbursed for it on the flexibility market.

This bidding behaviour is known as inc-dec gaming. The second case is particularly problematic, as there is no purpose to the commercial transaction concluded on the power market other than of being able to neutralise it later for congestion management purposes. In both cases, however, demand for flexibility is raised.

Another possibility is that of market participants deliberately causing grid congestion or making them more severe by placing extra capacity on the spot market in the expectation that the grid operator will then have to "buy back" this capacity on the flexibility market. This behaviour results in additional costs without any benefit with regard to congestion management if the only economic purpose to the offer on the spot market is to neutralise it later by an offsetting trade. In any event, in this case the outcome may be assumed to be macroeconomically inefficient.

Various approaches have been discussed in relation to strategic bidding behaviour: participants in the flexibility market could be obliged to submit binding unit-specific scheduling reports in advance. Statistical methods could compare scheduling reports at times "without a risk of congestion" with reports at times "with a risk of congestion"[68], thereby revealing any strategic bidding behaviour. Moreover, additional flexibility options could increase flexibility market liquidity and so reduce the risk posed by strategic bidding behaviour. Regulatory price capping is another potential instrument to limit strategic bidding behaviour.

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66 See neon/Consentec 2018; Hirth et al. 2019; Höckner et al. 2019.

67 Model calculations assume that redispatch demand could be increased by inc-dec bidding behaviour from 44 to over 300 terawatt hours, if stakeholders were able to perfectly anticipate congestion. Grid operator costs for relieving congestion would then be higher by approximately a factor of 3 than under today's cost-based redispatch system. In reality, however, it is unlikely that stakeholders would be able to perfectly anticipate congestion, and the effects would therefore be limited (Consentec 2019).

68 Höckner et al. 2019.

3.4.3 Contribution to climate protection

- **Use of climate-friendly generation units can be increased**
  Market-based flexibility procurement can contribute to climate protection if switchable loads are used to relieve grid congestion and electricity from climate-friendly generation units (in particular from RE and high efficiency CHP plants) is thereby able to replace fossil energy sources in other sectors.

3.4.4 Contribution to EU internal market in electricity

- **Flexibility from foreign units can be utilised**
  The possibility of cross-border procurement of flexibility is particularly significant from the standpoint of the internal market in electricity, and can be incorporated into a regional flexibility market. Given the territorial limits to their jurisdiction, German legislators cannot simply oblige foreign units to provide flexibility. Grid operators nonetheless buy in flexibility from abroad on the basis of voluntary offers under the current system.[69]

3.4.5 Feasibility and implementation costs

- **Costly implementation**
  The introduction of market-based mechanisms for procuring flexibility can give rise to considerable implementation costs, depending on how such mechanisms are configured. This is particularly true of the introduction of regional flexibility markets in the distribution grid.

3.4.6 Need for further research

Clarification is needed of the extent to which competition can be expected to work on regional flexibility markets and the extent to which market power would be likely to inflate prices. In particular, the extent to which flexible loads might be tapped needs to be clarified. The extent to which strategic bidding behaviour leads to economically inefficient outcomes must also be investigated. It is also necessary to investigate how the interplay of spot market and flexibility market can be configured to identify and rule out undesired strategic bidding behaviour. Finally, analysis is also needed of how any possible contribution to climate protection, in particular by dispatch of switchable loads, can be evaluated and how this can be taken into account when calling on flexibility options.

3.5 Increased incentives for non-market-based procurement of flexibility for congestion management

Congestion management flexibility is currently predominantly not procured using a market-based approach, but rather is made available on a mandatory basis at a grid operator's request. Remuneration is here in principle merely intended to cover costs, thereby leaving the unit operator involved neither better nor worse off than they would have been had they not been called upon to assist with congestion management. Such cost-based remuneration does not as a rule provide any economic incentives to disclose and provide existing flexibility potential or tap additional flexibility potential.

In light of these difficulties, cost-based flexibility procurement could be modified to create stronger incentives for voluntary flexibility provision and possibly to encourage

69 See also BMWi 2019-2.

the tapping of additional flexibility. Potential flexibility sellers could be identified by expression of interest procedures. Any remuneration would have to provide an incentive to participate, in other words, it would have to put the unit operator in a slightly better economic position than it would have occupied in the absence of the action taken by the grid operator. Unlike in the case of market-based procurement, however, it would not be the flexibility provider's asking price that would determine the level of remuneration but this would instead be calculated on the basis of the costs of flexibility provision, plus limited extra incentives. The grid operator's authority to oblige stakeholders to provide flexibility if the voluntarily offered volumes are inadequate would be maintained.

Load costs are generally difficult to determine. It is often therefore impossible to make a cost-based calculation of the remuneration supplemented by additional incentives. In such cases, load remuneration could be limited by the most favourable alternative flexibility option which is available for congestion management according to the above-described procedure (cost of flexibility provision plus additional incentives).

3.5.1 Effectiveness and short-term costs of congestion management and energy supply

- **Additional flexibility potential is tapped**
  Incentives to provide flexibility in the context of an expression of interest procedure offer some of the same advantages as market-based flexibility procurement. Such an approach can increase the flexibility on offer, so improving congestion management effectiveness and reducing costs. In particular, load-side flexibility would be easier to tap. The scope of the incentive effect would be subject to statutory limitations, however. As in the case of market-based procurement, there is uncertainty, above all at a low-voltage level, as to whether a relevant steering effect can be expected (e.g. due to the low cost impact) and whether the necessary expenditure (e.g. for new metering instrumentation) is justified.

- **Risk of higher costs and strategic bidding behaviour**
  Remuneration which improves the financial position of a unit operator, as described above, increases the costs of a given flexibility option compared with the present cost-based system, insofar as the costs can be correctly determined. Nevertheless, such an approach does not fundamentally conflict with the criterion of efficient congestion management, as incentives for flexibility provision are also a prerequisite of market-based flexibility procurement. Although such incentives cause extra costs, they are essential to the functioning of such a system. There can be no real objections to these costs either, since the extra costs caused by the additional financial incentives for the unit operators can be more than compensated for, as is the case if the wider range of flexibility options tapped (e.g. interruptible loads) leads to lower overall congestion management costs. If, however, the increased incentives fail to motivate significant numbers of additional sellers of relatively inexpensive flexibility, the cost of congestion management would rise overall.

  Higher remuneration of flexibility providers compared with the current market design lays the foundations for strategic bidding behaviour, as does market-based remuneration, but since such remuneration is modelled on the costs of flexibility, there is only a limited possibility of achieving higher margins by inc-dec gaming (see page 51).

3.5.2 Contribution to climate protection and to the EU internal market in electricity

- **Similar advantages as with market-based procurement**
  The advantages from the climate protection standpoint are fundamentally the same as with market-based procurement. The participation of foreign units in voluntary expressions of interest also opens up the possibility of cross-border procurement of flexibility, though German legislators cannot oblige foreign units to participate. The incentives to provide flexibility and possibly develop additional flexibility potentials are more limited, however, than in the case of market-based procurement.

3.5.3 Need for further research

More detailed analysis should in particular clarify how incentives for flexibility provision can be integrated into cost-based remuneration. The level of financial incentives needed to prompt unit operators to submit expressions of interest also needs to be established, as does the extent to which the inclusion of further units in congestion management can bring about cost advantages.

4 Conclusion

The current market design is based on a congestion-free electricity grid within the German electricity bidding zone for trades on the general electricity markets (power exchange futures and spot markets and OTC transactions). The trades lead to a dispatch of generation, storage and consumption units within the German bidding zone which takes only very limited account of the limited transmission capacity and thus the risk of grid congestion. Instead, grid operators have to intervene with additional measures when there is a risk of grid congestion. Such an approach is appropriate for electricity supply systems in which changes in grid usage proceed only slowly and can essentially be offset by grid expansion, which means there is only little need for corrective action by the grid operator. However, the energy transition and the expansion of cross-border electricity trading have for years been substantially accelerating the rate of change. As a consequence, there has been a sharp rise in corrective action by the grid operator within the German electricity bidding zone.

This trend would appear to be set to continue well into the future. Against this background, two factors would suggest that there is an urgent need to investigate whether a refined market design might be capable of improving the cost-efficiency and effectiveness of congestion management. **Firstly,** price signals for limited transmission capacity can influence the dispatch of generation, storage and consumption units. The market may in this way help to preemptively prevent congestion. This would have advantages for the effectiveness of congestion management, insofar as grid operators can dispense with subsequent corrective action. This might also be advantageous from a cost standpoint. **Secondly,** flexibility procurement methods can be changed. It would be highly advantageous if economic incentives were to increase the offer of flexibility and in particular flexible loads could also be used to a greater extent for absorbing power when feed-in levels are high. The aim is for grid operators to be able to procure flexibility more inexpensively in order to eliminate grid congestion.

This position paper discusses a total of five policy options for addressing these two areas. Table 1 provides an overview of the advantages and drawbacks of these options. It is apparent that there is no “silver bullet”, no single solution which is capable of eliminating all the problems. However, some of the options can be combined in order to address different aspects and offset their respective drawbacks. For instance, a reconfiguration of the German electricity bidding zone (option 2) or utilisation-based grid fees (option 3) could ensure that grid congestion are taken into account in dispatch decisions. Any remaining congestion could be eliminated by grid operators at lower costs if market-based procurement were expanded (option 4) or greater incentives provided for non-market-based procurement (option 5). All the options do, however, also have drawbacks which have to be carefully weighed up. The five options are briefly set out again below and their advantages and drawbacks summarised.

	Option 1 **Introduction of a nodal pricing system**	**Option 2** **Reconfiguration of the electricity bidding zone**	**Option 3** **Introduction of utilisation-based grid fees**	**Option 4** **Expansion of market-based procurement of flexibility**	**Option 5** **Increased incentives for non-market-based procurement of flexibility**
Category	Dispatch	Dispatch	Dispatch	Flexibility	Flexibility
Affected grid levels	Primarily extra-high- and high-voltage grid	Extra-high-voltage grid	Primarily extra-high-, high- and medium-voltage grid	Primarily extra-high-, high- and medium-voltage grid	Primarily extra-high-, high- and medium-voltage grid
Effectiveness	High	Higher than in the current situation. The better grid congestion is represented, the more effective they are	Depending on configuration, moderate to high	Higher than in the current situation	Higher than in the current situation
Short-term costs	Greatly reduced flexibility demand Risk of cost increases for electricity trading	Reduced flexibility demand Risk of cost increases for electricity trading	Reduced flexibility demand Effects on electricity trading merit closer investigation	Greater flexibility supply Risk of market power, inc-dec	Greater flexibility supply Risk of higher flexibility costs, inc-dec
Climate protection contribution	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation	Sector coupling incentive higher than in the current situation
Contribution to EU internal market in electricity	Cross-border application difficult	Highly compatible	Neutral	Highly c ompatible	Highly compatible
Feasibility and implementation costs	Low feasibility, very high implementation costs	High and possibly recurrent implementation costs	Very high for the development of a f utilisation-based tariff system, high for ongoing implementation	High implementation costs	Moderate implementation costs
Option combinable with …	Options 3, 4, 5	Options 3, 4, 5	Options 1, 2, 4, 5	Options 1, 2, 3, 5	Options 1, 2, 3, 4

Table 1: Comparison of policy options

4.1 Options for taking account of grid congestion in unit dispatch

A **nodal pricing system** sets separate electricity prices for all injections and extraction points of generation and possibly storage and consumption units taking account of electricity generation costs, the grid situation and possibly further parameters. Conceptually, nodal prices are ideal for avoiding grid congestion since they completely internalise the external effects resulting from the congestion. Introducing nodal prices would, however, mean a root and branch reform of the current market design and considerable objections have been raised against it. Firstly, there would be a need for tighter control of market power-related price margins since there would be a considerable increase in the risk of market-dominating positions due to modified territorial market delineation. Furthermore, the introduction of a nodal pricing system which includes the distribution grid level would involve major costs. Grid congestion in distribution grids is, however, becoming increasingly significant. In addition, congestion in the distribution grids interact closely with grid congestion on the transmission grid level. Finally, a nodal pricing system entails uniform management of grid operation, which would appear to be highly problematic to implement. This is particularly true for cross-border operations, where different operators' grids are involved. As a result, a nodal pricing system is not currently considered to be the priority option. A hypothetical, ideally functioning nodal pricing system could, however, serve as a benchmark for other forms of congestion management.

A **reconfiguration of the German electricity bidding zone** could help to model structural congestion more effectively and so take it into account in dispatch decisions for generation, storage and consumption units. There has, however, previously been a lack of clarity about the extent to which it is possible to model grid congestion across static zone borders. It is also unclear how frequently subsequent adjustments to zone borders might be necessary in order to take account of the displacement of structural congestion as a result of grid expansion and changes in grid usage. There is likewise little clarity about the effects on trading costs of modifying and in particular reducing the size of bidding zones. Negative effects on electricity trading could in particular arise from the risk of repeated reconfiguration of bidding zones and the associated lower planning reliability. The effects on trading costs would have to be investigated in greater detail and, as far as possible, quantified so they can be weighed up against the cost benefits of reconfiguring the bidding zone. Furthermore, grid congestion within bidding zones cannot be avoided by application of this option for action. If bidding zones are made relatively large (e.g. one northern and one southern German bidding zone), the risk of grid congestion might well subsist to a considerable extent.

Introducing utilisation-based grid fees would increase grid usage fees as a function of the degree of grid utilisation and thus the probability of grid congestion. Such a reform of the grid tariff system can create incentives to take account of transmission capacity limitations within bidding zones in the dispatch decisionsfor generation, storage and consumption units, while simultaneously fitting in with the existing system (bidding zone-wide electricity price setting, separate grid fees). It is thus fundamentally considered as a means for pre-emptively preventing grid congestion within bidding zones. There is, however, virtually no experience of detailed configuration and few theoretical investigations have likewise been carried out. It would consequently make sense to carry out a trial which initially only roughly models the congestion situations and avoids any excessively restrictive effect of grid fees. The aim would be to gather experience as to how grid fee signals should be set and the extent to which they may be expected to have a controlling effect on unit dispatch. Market participants in such a system would have greater latitude to develop business models on the basis of the (anticipated) energy prices and grid fees than in the case of nodal price setting by a central operator.

4.2 Options for procuring flexibility

At present, grid operators intervene to a considerable extent in the dispatch of generation and storage units and to a slight extent also of consumption units in order to eliminate grid congestion. Grid operators will probably have to continue to depend to a considerable extent on third party flexibility for congestion management, even if more grid congestion were in future to be preemptively prevented. At the same time, conventional large-scale power plants, which have previously primarily been used for providing flexibility, will become increasingly unavailable. Using flexibility from smaller scale generation and storage units and in particular rom consumption units will thus become increasingly significant. In this respect, it would seem to be important to make flexibility from such units more readily available than it is in the present system. Flexibility for congestion management has previously mainly been procured by non-market-based mechanisms which oblige unit operators to provide flexibility in return for cost-based remuneration. Two further options for action to improve the availability of flexibility were investigated.

An expansion of **market-based procurement of flexibility** fits well with the guiding principle of a competition regime, according to which supply and demand are coordinated through markets, providing a market failure situation (e.g. in the form of a market-dominating position by flexibility providers) does not prevail. Functioning markets generally provide efficient incentives for the provision of flexibility including load-side flexibility and may release further innovation potential. It is, however, necessary to eliminate bidding behaviour which has no benefit for the energy supply system. Market participants must not have the ability to intentionally create grid congestion or make them more acute by marketing additional capacity on the spot market in the expectation that the grid operator will then have to “buy back” this capacity on the flexibility market to eliminate congestion. Other situations, in which a market participant for example holds back flexibility on the spot market in order to sell it at a higher price on the flexibility market, do not fundamentally conflict with a competition regime. Rather, the spot market price in a uniform German electricity bidding zone does not reflect the particular (geographically justified) value of this flexibility and consequently provides no incentive for providing flexibility and innovation, which may in turn reduce costs. Further discussion of the advantages and drawbacks of such (“strategic”) bidding behaviour is required here. Furthermore, such bidding behaviour, insofar as it is considered to be a negative phenomenon, may at least to some extent be limited by regulatory control mechanisms. Market-based approaches such as regional flexibility markets should therefore be further investigated.

Obstacles such as market power problems or higher flexibility demand and higher costs in the event of strategic bidding behaviour may suggest that flexibility procurement for congestion management should at least in part be non-market-based. **Increased economic incentives for non-market-based procurement** may improve the disclosure and deployment of existing flexibility as well as the development of additional flexibility potential. Remuneration must be calculated such that it puts the unit operator in a slightly better economic position than it would have occupied in the absence of the action taken by the grid operator. Such an approach limits additional costs compared to a purely cost-based remuneration, in particular in the event of market failure situations or strategic bidding behaviour. In a more detailed configuration, it would have to be clarified how incentives for flexibility provision can be integrated into cost-based remuneration. This also applies to the level of economic incentives which are required to have an effect. In order to assess this option for action, the extent must be clarified to which it is possible to achieve cost benefits which exceed the costs of the additional flexibility incentives.

The following points may be made:

- Suitable **price signals** can ensure that the available transmission capacity is taken into account in generation, storage and consumption unit dispatch and grid congestion are **preemptively prevented**. Such signals can apply both to the wholesale electricity price and to grid fees. Such approaches should be more thoroughly investigated.

- **Utilisation-based grid fees** have the advantage that they can be incorporated into the current system of a uniform German electricity bidding zone. Such an approach would, however, first have to be developed and trialled.

- **Market-based procurement of flexibility** for eliminating subsisting grid congestion fits well with the guiding principle of a competition regime. It would provide incentives to make better use of flexibility potential, specifically on the load side, and to tap any innovation potential. The functioning of electricity and flexibility markets would, however, have to be monitored. The same applies if increased financial incentives were to be added on to the current cost-based procurement system. Such approaches should be pursued further.

- All the options have their **advantages and drawbacks**. A **combination** of measures should therefore be considered in order to achieve the best possible outcome.

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The Academies' Project

With the initiative “Energy Systems of the Future”, acatech – National Academy of Science and Engineering, the German National Academy of Sciences Leopoldina and the Union of the German Academies of Sciences and Humanities provide impulses for the debate on the challenges and opportunities of the German energy transition. In interdisciplinary working groups, some 100 experts from science and research develop policy options for the implementation of a secure, affordable and sustainable energy supply.

"Electricity market design" working group

Today's regulatory issues in the electricity market differ from those at the turn of the millennium, when corner stones for Germany's energy market design were set by market liberalization. The market design must therefore be adjusted. The interdisciplinary working group set itself two priorities: the management of grid congestion and a reform of energy prices in order to facilitate sector coupling.

The results of the working group's efforts around grid congestion have been made available in two formats:

1. The **analysis** "*Grid Congestion as a Challenge for the Electricity System. Fields of Regulation, Status Quo and Policy Options"* comprehensively documents the current state of scientific knowledge regarding the origin of grid congestion as well as the current set of measures for congestion management. Furthermore, it provides a detailed explanation of the policy options proposed by the working group, and their advantages and drawbacks.

2. The **position paper** *"Grid Congestion as a Challenge for the Electricity System. Options for a Future Market Design"* presents the results in compact form.

The results relating to the reform of energy prices are separately published.

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