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The German incentive regulation and its practical impact on the grid integration of renewable energy systems

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ABSTRACT

This paper investigates the interplay between the German incentive regulation and renewable capacity integration. A comprehensive review of the current incentive regulation scheme and its 2016 amendment is first presented. Then, results of ten representative interviews with large-scale distribution system operators are analyzed. Firstly, all necessary grid integration measures could so far be implemented. Secondly, creating proper incentives for intelligent operating equipment to partly substitute conventional grid expansion remains a challenge. Thirdly, the new curtailment regulation of 2016 is welcome, but will not become a substitute for grid expansion as long as renewable integration rates are high. Moreover, the discussions on further improvements to the incentive regulation scheme reveal a distribution conflict between grid operators and grid users.

1. Introduction

1.1. Background

With the progression of the energy transition in Germany, the installed capacity of renewable energy has increased significantly. For example, the installed capacity of photovoltaic and wind power increased to 40 GW each by the end of 2015 [1]. Given the large number of renewable energy sources, the energy system has become much more decentralized in character. This brings the electricity distribution grids into focus, since 90% of the renewable energy sources are connected to them [1].

Spurred by the steady decline in prices, the expansion of renewables has become a major trend on the international stage too [2]. Many countries have reacted to this development, in part by overhauling the regulatory framework conditions for decentralized energy [3]. These countries can expect to see developments comparable to those in Germany, with a central question revolving around the regulatory challenges posed by the grid integration of decentralized energy.

This article is part of a project analyzing the practical experience of German distribution system operators (DSOs) with the integration of photovoltaic and wind power systems into the electricity grid. Within this framework, the present article investigates the regulatory aspects of financing grid expansion and operation driven by the increased integration of renewable energy. The analysis is based on findings from a series of interviews carried out with major large-scale grid operators in Germany, as well as on evaluations of laws, regulations, and other relevant studies. The paper thus complements analyses of the technical challenges posed by the integration of decentralized energy systems into the distribution grid [4,5]. Bayer et al. [4] state that the technical challenges limiting the hosting capacity of renewables are primarily related to respecting the thermal rating of grid equipment and complying with the permissible voltage range. Papathanassiou et al. [5] show that additional technical challenges include guaranteeing power quality, ensuring grid reliability and providing network protection. The main regulatory challenge is to provide a framework that allows DSOs to make the necessary investments in relevant technologies and at the same time create incentives for the DSOs to manage the grids in the most efficient manner.

1.2. Literature

To regulate the revenues for DSOs, legislators traditionally used schemes known as cost-plus or cost-of-service mechanisms as explained by Gómez [6] and Lazar [7]. These mechanisms grant

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DSOs a predefined return on investments and the reimbursement of operational expenses. By contrast, an incentive regulation aims to encourage DSOs to improve their performance. Hence, this approach is also called performance-based or output-based regulation. Performance-based regulations were gradually introduced around the world along unbundling and liberalization processes as detailed by Gómez [6]. Lazar [7] uses performance-based regulation as the general term and distinguishes three variants: rate cap regulation, incentive-based regulation and revenue cap regulation. Rate cap regulation ties the allowed growth in revenue to changes in sales volume and typically to inflation rates. Incentive-based regulation ties regulation to some kind of performance incentive. Revenue cap regulation sets a formula for the total allowed revenue. The latter regulation belongs to the category of "high-powered regulation" as defined by Agrell et al. [8], since the DSO receives the residual of the ex ante approved revenue and ex post realized cost.

Joskow [9] shows how incentive regulation and cost-of-service regulation represent two opposite ends of the spectrum: in its purest form, an incentive regulation would mean that the revenue cap is never changed by the regulator. This would lead to great incentives for the DSO to lower costs and hence increase profits. In a pure cost-of-service regulation, prices (or revenues) would always be adjusted so as to reflect the DSO's cost savings, impeding any incentive for the DSO to reduce costs. Joskow points to the obvious difficulty of finding the right time and height of adjustment of the revenue cap [9]. So do Cambini and Rondi [10] when they show that in practice there is no complete switch to incentive regulation. Instead, there are just elements of the new regulation that are added to the old. Germany is a suitable example for such an evolutionary approach. When the incentive regulation was created, it was combined with elements of the old cost-of-service regulation. For instance, there is a revenue cap that is set for a period of time, but its readjustment at the end of the period introduces updated costs. In addition, some costs are defined as "permanently non-controllable" and raise the revenue cap accordingly, resembling cost-of-service regulation. Furthermore, the formula of allowed revenue combines features of rate cap regulation like inflation rate and of incentive-based regulation like performance incentives.

Agrell and Grifell-Tatjé [11] analyze the adjustment of the revenue cap from the DSO perspective. They show that the investment behavior of DSOs is influenced by strategic gaming. This means that DSOs may maintain inefficiencies despite being regulated by an incentive scheme if the risk of not receiving the benefits of an efficiency investment is too high. Other papers analyze more specific aspects of incentive or performance-based regulation. Égert [12] estimates the effect of shifting away from traditional cost-of-service regulation and the impact of an independent regulator on investments. His results suggest that the introduction of an incentive regulation alone did not improve investments. However, once an independent regulator was established, too, investments did improve significantly. Cambini and Rondi [10] specifically analyze the investment behavior of European energy utilities in the period of 1997–2007, namely in the course of switching to incentive regulations in the late 1990s. They find that DSOs appear to invest more under the new regime. Furthermore, investments are positively related to the allowed capital cost but negatively related to the productivity requirements. Huang and Söder [13] propose a new method to quantify the interplay between incentive regulation, network investment and its performance in the event of integrating distributed generation. Thereby, the DSOs gain insights into the interaction among incentives, costs and performance, whereas regulators are ably to quantify the impacts of the incentives on network investment and performance.

With regard to Germany as a case study, there is a multitude of German-language publications dedicated to the general topic of incentive regulation. For instance, so-called practice handbooks written by consultancy firms contain extensive descriptions of the relevant laws [14]. In addition, various books address specific aspects. Luig [15] describes optimization potentials of the German scheme, and Kirchberg [16] provides examples of investment calculations and practical experiences. In 2015, the Federal Network Agency (Bundesnetzagentur), published a legally prescribed evaluation report [17], which served as an important basis for our interview series.

The English-language literature on the German incentive regulation is, however, very limited. Following an empirical approach, Cullmann and Nieswand [18] show, for instance, that the timing of investments for German DSOs is influenced by the incentive regulation currently in place. Another general study [19] includes a country report on the German electricity distribution, however, the focus is set on the grid tariff structure and incentive regulation is only superficially addressed. In terms of integrating renewable energy into the German electricity grids, Nykamp et al. [20] discuss the incentives of the present regulation with regard to intelligent solutions, showing that there is a lack of investment incentives. Furthermore, Mateo et al. [21] investigated the barriers to large-scale integration of photovoltaics at European level, including Germany. They found that the current regulation does not promote smart grid investments. Ropenus et al. [22] give a general overview of the possible interactions between regulations of DSOs and support schemes for distributed generation in five countries, namely Denmark, Germany, The Netherlands, Spain and the United Kingdom. They conclude that in Germany there are no locational signals for the optimal placement of distributed energy systems from a grid perspective. This is attributed to the absence of use-of-system charges in combination with "shallow connection charges" (i.e. the owner of the distributed energy system pays for direct connection costs only and maybe a transformer) [22].

None of the studies mentioned above provides a sufficiently detailed review of the German incentive regulation for a non-German audience, without requiring prior knowledge of the system. Such an in-depth analysis is, however, necessary in order to understand the impact of the continuing renewable energy expansion on the financing of the distribution grids. Not only does incentive regulation establish the level of the revenues that are charged to grid users, but it is also meant to create incentives for decreasing the costs of grid operation and expansion. The findings of this paper will, in turn, help determine which principles of the German incentive regulation are transferable to other countries.

The introductory section on Germany's energy transition is followed by a section explaining the mechanisms of the German incentive regulation system for the distribution grid. This central part of the paper is completed by a presentation of the interview results and a discussion of those results against the background of incentive regulation.

2. The German energy transition and the role of decentralized renewable energy

The transformation of Germany's energy system can be traced back to the 1980s and gained additional momentum following the Chernobyl nuclear disaster of 1986 [23]. In 2010, long-term goals were for the first time defined for the share of renewable energy in the consumption of electricity and in the overall final energy consumption [24]. After the Fukushima nuclear disaster in 2011, the German government overhauled the plan for the nuclear phase-out [25]. This transformation of the energy system became known around the world as the *Energiewende*. The core of the concept is the move away from fossil and nuclear energy generation towards the development of an energy system that by the year 2050 is to be virtually greenhouse gas-free and based on renewable energy sources.

2.1. Renewable Energy Sources Act (EEG)

The central instrument and driver for the expansion of renewable energy in Germany is the Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz* – EEG). It was adopted in the year 2000 and has since been revised several times. The law that preceded the EEG was the Electricity Feed Act, which had been in effect since 1991. During the 1990s there were also several support programs for wind power and photovoltaic systems. The following characteristics of the EEG have so far enabled the expansion of renewable energy [26]:

- The obligation of the grid operator to connect the system
- A remuneration system with fixed remuneration rates that are higher than the market price, differentiated according to technology and usually guaranteed for 20 years
- A feed-in priority for the electricity produced

According to the EEG, grid operators are obliged to choose the connection point that is in closest proximity (i.e. most economical to reach) and most suitable in terms of voltage level. For systems up to 30 kW, this is the building connection point. The system to be connected must meet certain technical specifications such as remote control capability in order to temporarily reduce the feed-in capacity for grid-assistive behavior.

2.2. Role of decentralized renewable energy sources

The EEG has played a key role in the successful expansion of renewable energy in Germany [26], which has been advanced primarily through the leading technologies of onshore wind power and photovoltaics, as these have turned out to be the most cost-effective renewable technologies. In recent years, due to the decline in prices for rooftop photovoltaic technology, self-consumption of the generated electricity has become more widespread. The ongoing development of battery storage and other advanced technologies such as demand response may further promote self-consumption. Nevertheless, utility-scale power plants for biomass, onshore and offshore wind energy, and ground-mounted photovoltaics remain the main contributors to Germany's renewable energy mix.

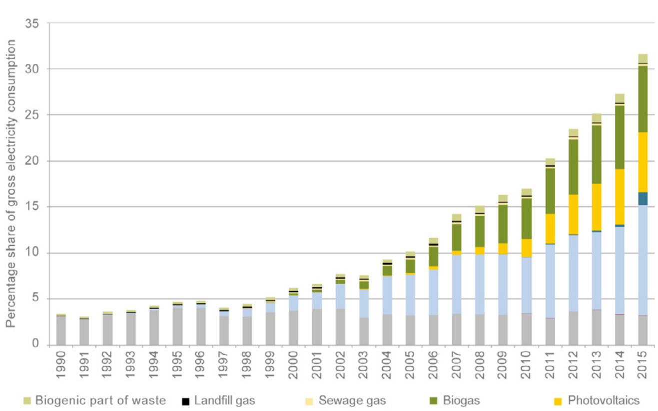

Fig. 1. Development of the share of renewable energy in gross electricity consumption in Germany, calculated from data in Ref. [27].

As Fig. 1 shows, the share of renewable energy has grown steadily since the late 1990s [27]. The steady growth of biomass, photovoltaics and wind power suggests a fundamental restructuring of the entire energy supply system. This also applies in particular to the expansion and reinforcement of the electricity grids. In the "old" energy world, electrical energy was mainly generated at the highest voltage levels and consumed at lower levels. This resulted in a unidirectional flow of electricity from higher to lower voltage levels. Due to the increasing degree of decentralization, with 90% of renewable system capacity connected to distribution grids, there is now an increasing amount of reverse current running from lower to higher voltage levels [28]. This brings with it a range of technical and organizational challenges, since the grids were not designed for this situation [29].

2.3. German distribution grids

The German electricity grid is made up of the transmission grid, with a number of connections to other extra-high voltage grids of surrounding countries, and the exclusively inner-German distribution grids. The transmission grid in Germany is divided into four control regions, with one transmission system operator responsible for each. These operators are responsible for electricity lines totaling over 35,000 km in length at the voltage levels 380 kV and 220 kV of the alternating-current grid [30].

As of August 2016, the German distribution grid is owned and operated by a total of 879 distribution system operators, or DSOs [30]. Due to this large number of operators and the differing regional conditions, the structure of the grids is diverse and ranges from small local grids to large-scale grids, encompassing both rural and urban areas. The voltage levels in the distribution grid are 400 V (low voltage), 10/20/30 kV (medium voltage) and 110 kV (high voltage). The lower voltage levels are connected to the respective higher voltage level via substations, and the high-voltage grid is connected to the transmission grid. The total length of all distribution grid lines amounts to approximately 1.8 million kilometers, which makes up 98% of the electricity grid in Germany [4].

3. The regulation of the German distribution grids

3.1. Background: liberalization and grid regulation

The concept of a liberalization of the energy markets has its origins in the 1980s and was influenced by the monetarist and public choice theories that were being developed at the time. In line with those theories, public sectors that previously had a monopolistic organization – such as the electricity industry – were to be organized with a greater orientation toward market economy and efficiency. Accordingly, companies that had until then been integrated, in which the entire value creation chain – from energy generation to distribution to sales – had been organized under one roof, were divided into economically autonomous units [31]. The electricity grids, however, constitute a natural monopoly due to the fact that as a rule, a single electricity grid is more economical to operate than multiple parallel grids. If a monopoly exists, however, grid operations must be regulated. Another option is the simulation of competition between the grid operators. Moreover, if the grids are owned by vertically integrated companies, the regulation needs to ensure grid access in a non-discriminating fashion [32–34].

The German regulatory scheme regarding the liberalization of the energy industry is based primarily on the 2005 Energy Act (EnWG) [35] and is also implementing various European guidelines into national legislation [36]. In 2007 the Federal Government created the so-called Incentive Regulation Ordinance (ARegV) to govern the specific design of grid regulation [37]. The ARegV applies to all grid operators, i.e. for gas and electricity networks, as well as for transmission and distribution grids. The following sections refer to the incentive regulation for DSOs of electricity grids.

Incentive regulation takes place within specified regulatory periods lasting five years each. Section 3.2 describes the incentive regulation for the first two regulatory periods (2009–2013, 2014–2018). Section 3.3 presents the main features of the ARegV amendment, which was passed in 2016 for the third regulatory period (2019–2023). In the course of this amendment, fundamental elements of the ARegV were revised, changing the validity of some of the principles from the first two regulatory periods.

3.2. Incentive Regulation Ordinance for the first two regulatory periods (2009–2018)

The next two subsections, 3.2.1 and 3.2.2, present the fundamental principles of the budget approach and of efficiency benchmarking, which are both central concepts of the ARegV. Subsection 3.2.3 explains all the components of the regulation formula that sets the revenue cap of the DSOs.

3.2.1. The principle of the budget approach

The underlying principle behind the ARegV is to regulate the DSO revenues rather than their costs. This is known as the budget approach and is based on the revenue cap mechanism. Such a mechanism creates an incentive to lower the costs during the regulatory period by allowing DSOs to retain some of the efficiency gains [9,10].

Additional efficiency incentives are implemented in the form of the sectoral productivity factor and efficiency benchmarking between all of the German DSOs. The legislator's underlying objective is to keep the overall costs of distribution system operation as low as possible.

Within the framework of the budget approach, a revenue cap is set for each of the five-year regulatory periods. This revenue cap defines the permissible amount that the grid operator can allocate to his customers in the form of grid charges. The determination of the revenue cap constitutes the focus of the incentive regulation as well as of this paper.

Fig. 2 illustrates in a simplified manner the principle of the budget approach. The revenue cap is set each regulatory period for each DSO according to his total costs. These costs are determined following a financial review that takes the so-called base year as a basis. The base year is the business year occurring three years before the start of the respective regulatory period. For instance, 2011 is the base year for the 2014–2018 regulatory period.

The profits of the DSO result from the difference between revenue cap and actual costs and are depicted in Fig. 2 by hatched bars. Lower operating and capital costs increase profit. The profits can then be used in the financing of new investments. However, the costs for new investments are only taken into account when the new revenue cap for the following regulatory period is set according to the base year amount. The revenue cap can thus increase or decrease, as depicted in Fig. 2. If the costs in the new base year are higher relative to the previous base year, the revenue cap will increase as well. On the contrary, if the base-year costs are lower, then the revenue cap will decrease in the following regulatory period.

As illustrated in Fig. 2, the revenue cap is set ex ante and the profits depend on the actual costs of the DSOs for the respective year. As a consequence, the costs and profits for the current and upcoming years are left blank.

Theoretically, this budget approach can also create the financial incentive to postpone investments until the base year in order to reduce the delay of revenue reimbursements, and to maximize the revenue cap during the following regulatory period. Nonetheless, the DSO obligation to connect new systems and to expand the grid restricts the practical implications of this financial incentive. Moreover, the above-mentioned financial review represents another control mechanism, preventing the DSOs from inflating the base-year costs.

Under certain conditions, the legislation stipulates an increase in the revenue cap during a regulatory period. For instance, this can occur if the supply responsibility of the DSO is expanded or if individual projects are carried out at 110 kV level. In practice, the revenue cap can therefore change each year, as long as the legal requirements are met [17]. This is schematically illustrated in Fig. 3.

3.2.2. The principle of efficiency benchmarking

Efficiency benchmarking plays a central role in incentive regulation. The shares of “efficient” and “inefficient” costs are thereby calculated individually for each DSO, through a comparison among all German DSOs. The annual reduction of the revenue cap by a share of the inefficient costs is meant to act as an incentive for the DSOs to reduce their costs to an efficient level.

For the efficiency benchmarking, there is a standard procedure in place for DSOs with a customer base larger than 30,000 and a simplified procedure for small DSOs of up to 30,000 customers. Of the 879 German DSOs, only 182 are subject to the standard procedure [8]. For these DSOs, the efficiency benchmarking is carried out based on two methods, the non-parametric Data Envelopment Analysis (DEA) and the parametric Stochastic Frontier Analysis

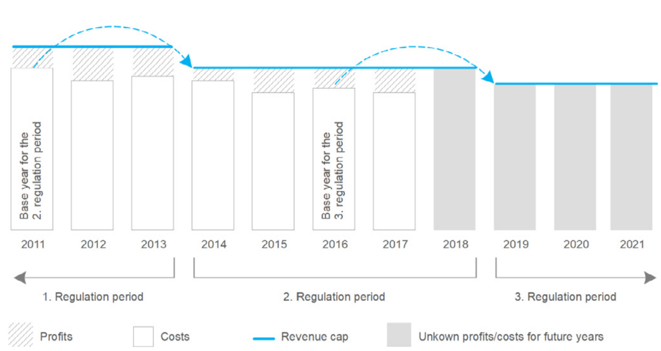

Fig. 2. Principle of the budget approach. This is our own simplified representation based on the Incentive Regulation Ordinance [37] and which does not take into consideration some relevant factors such as inflation compensation and efficiency benchmarking. Note that the relative changes were oversized in order to enhance readability.

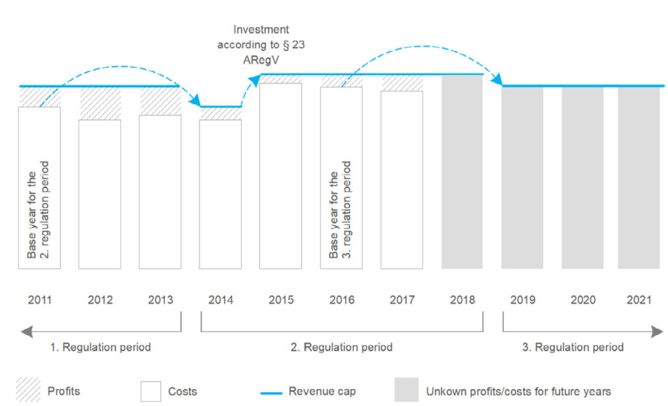

Fig. 3. Exceptions to the budget approach, depicted in a simplified fashion. This is our own representation based on the Incentive Regulation Ordinance [37].

(SFA). For both methods, the ARegV stipulates a set of parameters, which provide a basis for analysis and are listed in Table 1. The main distinction between the two methods lies in the different weighting of these parameters.

Unlike the DEA method, the influence of the parameters on the respective costs of each DSO is estimated in the SFA method using statistical methods (regression model). The parameters are weighted with the aim of taking structural differences between the DSOs more explicitly into consideration when calculating the efficiency values. These differences relate both to the supply responsibilities and to the environmental conditions of the DSOs.

An example of a structural difference in relation to the supply responsibility could be the higher installed capacity of rooftop photovoltaic systems in Southern Germany. In terms of their environmental conditions, other DSOs may have a particularly large supply area. These factors must be considered in the efficiency analysis.

Compared with the DEA method, the SFA method strives to take better account of those cost differences of grid operation that are due to structural factors. The SFA method depends, however, on the correct specification of the parameters and is thus more time-consuming. So both methods have their advantages and disadvantages [8].

In keeping with the principle of prudence, the use of both methods is compulsory so that the deficiencies of each model can be compensated for. Furthermore, in both methods, outlier analyses are carried out to eliminate the respective DSOs that emerge as the most efficient (the “outliers”). As a result of eliminating the outliers, the efficiency of the remaining DSOs increases considerably.

Following the outlier analyses, the final efficiency values of the DSOs are calculated twice using each method, not only on the basis of the actual capital costs but also on the basis of the standardized capital costs to account for distortions that may arise in particular from the different age structures of the grid equipment [37]. In this way a total of four efficiency values are generated for each DSO. Of these four values, the best is selected in each case (the “best-of-four procedure”).

The outlier analyses combined with the best-of-four procedure result in overall high efficiency values. During the second regulatory period, for example, 55 of the 182 DSOs reviewed received an efficiency value of 100%, and only 24 DSOs scored under 90% [8].

In the simplified procedure for small DSOs, a uniform efficiency value is determined for all the DSOs under consideration; in the second regulatory period, the value was 96.14% [38]. This value is essentially obtained as the weighted average of the efficiency values resulting from the standard procedure of the previous period.

3.2.3. The cost components of the Incentive Regulation Ordinance

The annual revenue cap is calculated with the help of the formula below. The name and the reference year of the parameters are provided in the nomenclature box. This formula takes into account the budget approach and also implements the results of efficiency benchmarking. A series of additional parameters also influence the revenue cap of the respective year. In this subsection, the individual components of the formula are presented and explained.

$$EO_t = KA_{dnb,t} + \left(KA_{vnb,0} + (1 - V_t)KA_{b,0}\right)\left(\frac{VPI_t}{VPI_0} - PF_t\right)EF_t + Q_t + (VK_t - VK_0) + S_t$$

The ARegV divides the total costs of the DSO into permanently non-controllable cost shares $KA_{dnb,t}$, temporarily non-controllable cost shares $KA_{vnb,0}$ and controllable cost shares $KA_{b,0}$. These represent the main parameters. In the language of efficiency benchmarking, the temporarily non-controllable cost shares correspond to the “efficient costs”, while the controllable cost shares correspond to the “inefficient costs”.

Given the annual adjustments to the revenue cap, several parameters are marked with the index t. This index refers to the respective current year of the five-year regulatory period. By contrast, parameters with the index 0 refer to the base year, which generally occurs three years before the beginning of the regulatory period. These parameters remain constant throughout the regulatory period.

(i) Permanently non-controllable cost share $KA_{dnb,t}$

The permanently non-controllable cost share consists of a firmly defined list of positions, which are not at all or hardly influenced by the DSOs. This includes, on the one hand, cost positions such as costs of the overlying grid levels, EEG remuneration for owners of distributed renewable energy systems or concession fees. On the other hand, it also includes firmly defined cost positions of grid operation, such as approved investments at the 110 kV level. The permanently non-controllable cost share is adjusted on an annual basis, with the adjustments leading to a corresponding annual change in the revenue cap.

(ii) Budget approach and efficiency benchmarking $(KA_{vnb,0} + (1 - V_t)KA_{b,0})$

This term is at the core of the incentive regulation, as it includes the implementation of the budget approach as well as efficiency benchmarking.

The temporarily non-controllable cost shares $KA_{vnb,0}$ and the controllable costs $KA_{b,0}$ are those costs that can be redeemed by the DSO during the five-year regulatory period. Both parameters remain constant during the regulatory period. Their values are determined on the basis of historical costs in the base year. Their sum corresponds to the total costs less the permanently non-controllable costs in the base year − referred to below as residual costs.

Table 1
Parameters for the DEA and SFA methods according to the ARegV.

	Optional parameters for the third regulatory period	Required parameters for the first two regulatory periods
Number of connection points	X	X
Size of area supplied	X	X
Total length of power lines (system length)	X	X
Simultaneous annual peak load	X	X
Annual energy feed-in	X	
Distributed energy systems, especially number and capacity of wind and solar power systems	X	

$$KA_{vnb,0} + KA_{b,0} = Total\ costs - KA_{dnb,t}$$

The level of the shares of $KA_{vnb,0}$ and $KA_{b,0}$ in the residual costs is determined through efficiency benchmarking. For instance, if the DSO has an efficiency value of 80%, this corresponds to a temporarily non-controllable cost share $KA_{vnb,0}$ of 80% and a controllable cost share $KA_{b,0}$ of 20% of the residual costs.

The distribution factor V_t is meant to ensure that the DSOs reduce their costs by the inefficient controllable cost share $KA_{b,0}$. This takes place through an annual increase of V_t, which results in a gradual decrease of (1-V_t) and thus the entire term (1-V_t) $KA_{b,0}$ to zero. V_t thus sets the target reduction trajectory for the inefficient costs. This is illustrated in Table 2 by way of a simplified example.

As the term (1-V_t) $KA_{b,0}$ leads to a lowering of the revenue cap over the duration of the regulatory period, DSOs have a clear incentive to gain the highest possible efficiency rating in efficiency benchmarking.

(iii) Consumer price index and sectoral productivity factor $\left(\frac{VPI_t}{VPI_0} - PF_t\right)$

VPI_0 is the overall consumer price index of the base year and VPI_t is the valid value for the respective regulatory year. For availability reasons, the calculation of this value is based on the consumer price index of the year two years prior to the respective regulatory year. The quotient from VPI_t and VPI_0 (expressed as a percentage) represents the overall economic inflation rate relative to the base year.

The general sectoral productivity factor PF_t is an efficiency target specific to this sector, which – unlike the individual efficiency value derived from efficiency benchmarking – is applied uniformly to all DSOs, since it is assumed that productivity in this sector is increasing at a faster rate than in the economy as a whole [17]. This mechanism is intended to pass on the productivity increases within this sector to grid customers.

For example, the PF_t value for the second regulatory period is 1.5% p. a.. Consequently, the revenue cap is raised not by the total overall economic inflation value but only by the inflation value less the sector-specific productivity factor (see Table 3). In this way the revenue cap either rises at a slower rate than overall economic price development or sinks altogether.

Table 2
Reduction of inefficient cost shares, shown in a simplified manner.

Year	V_t	(1- V_t)	$KA_{b,0}$	(1- V_t) $KA_{b,0}$
2014	0.2	0.8	200000 €	160000 €
2015	0.4	0.6	200000 €	120000 €
2016	0.6	0.4	200000 €	80000 €
2017	0.8	0.2	200000 €	40000 €
2018	1.0	0.0	200000 €	0 €

Table 3
Development of the consumer price index, inflation rate, and sectoral productivity factor, shown in a simplified example.

Year	VPI_0 (2012)	VPI_t	VPI_t/VPI_0	PF_t	VPI_t/VPI_0 - PF_t
2014	102.1	104.1	1.020	0.015	1.005
2015	102.1	105.7	1.035	0.030	1.005
2016	102.1	106.6	1.044	0.046	0.998
2017	102.1	106.9	1.047	0.061	0.986
2018	102.1	107.2	1.050	0.077	0.973

(iv) Expansion of supply responsibility using the expansion factor EF_t

The expansion factor is applied when there is a "lasting change in supply responsibility" relative to the base year. For this, the DSO must be able to show evidence of a cost increase of at least 0.5% per year.

If this condition is met, the expansion factor is recalculated every year based on physical parameters prescribed in the ARegV. These parameters are the number of feed-in points, the size of the supply area, and the annual peak load. The Federal Network Agency can continue to define further parameters, among other things for connecting additional renewable energy systems to the grid.

(v) Quality element Q_t

Furthermore, the regulatory authority provides for increases in or deductions from the revenue cap when the reliability of supply deviates considerably from the average of all DSOs in a given year. Based on key figures (e.g. duration and frequency of interruptions to supply), weighted averages are calculated for all DSOs for the last three years. In a further step, the deviations are determined and afterwards the increases and deductions are calculated.

(vi) Volatile (non-controllable) cost shares $(VK_t - VK_0)$

The volatile cost shares include for instance fluctuations that come about in the procurement of energy to cover power losses. The additional energy is required for the balancing of physically determined energy losses in the power grid. The DSO procures the necessary amounts of energy on the market. In this way cost shares that are subject to high fluctuations can be allocated without further delay.

(vii) Balance offsetting from the previous period S_t

Finally, account balancing takes place relative to the previous regulatory period in order to balance out any differences between actual revenue generated and the permissible revenue cap. This is necessary because the grid charges, which generate the actual revenues, are also based on forecasts of electricity supply or number of customers. The balance – whether positive or negative – is offset evenly over the next regulatory period.

(viii) Revenue cap and grid charges EO_t

The revenue cap represents an absolute value that is allocated to the grid users. Details of the calculation of grid charges (kilowatt-hour price and capacity price) are regulated in the Electricity Grid Charges Ordinance [39].

3.3. Key changes for the third regulatory period (2019–2023)

The Incentive Regulation Ordinance, which has been in effect since 2009, was subject to an evaluation according to its mandate [37]. Based on this evaluation, the Federal Network Agency published recommendations for the revision of the ARegV, which led to its amendment in 2016 [40]. This section provides a short overview of the key changes in the amendment to the ARegV, which is valid starting with the third regulatory period. In addition, it briefly outlines how the interest rate on equity capital is determined for this regulatory period.

3.3.1. Capital expenditure adjustment

With the introduction of the capital expenditure adjustment, capital costs are no longer subject to the budget approach. Together with their planning costs, the capital costs of new investments are integrated into the calculation of the revenue cap without delay, i.e. in the year in which they have an impact on revenues. Changes in the capital costs of grid assets are also considered in the annual recalculation and lead to a corresponding adjustment of the revenue cap. Thus, from the third regulatory period on, the fundamental principle of the budget approach will be abandoned for investments and will continue to apply only in the case of operating costs. This represents the most important change instituted by the amendment to the ARegV.

As a result of this reform, the capital cost share to the revenue cap is calculated to the year. The immediate integration of the new investment costs tends to result in an increase in the revenue cap. At the same time, falling capital costs (lower depreciation and interest expenses) from previous investments result in a lowering of the revenue cap.

The introduction of the capital expenditure adjustment reinforces the existing tendency of the ARegV to favor capital-intensive solutions [17]. The process of efficiency benchmarking is, however, retained. This induces two contrary effects. On the one hand, capital cost-intensive solutions are increasingly favored, but on the other hand there is a risk that these costs will only be partially recognized retroactively in efficiency benchmarking. This second aspect is, however, weakened by the fact that efficiency is only measured relative to the other DSOs. This in turn means that when all DSOs behave in the same way, the risk of receiving a lower efficiency value is reduced.

The adoption of the capital expenditure adjustment leads to all investments having a similar economic effect as the expansion investments at the 110 kV level previously had. That said, in the case of capital expenditure adjustment, reviews are carried out across the board. By contrast, reviews were only carried out on a case-by-case basis for the 110 kV level in the first two regulatory periods, and the investment costs were subject to further efficiency benchmarking in the following regulatory period.

The capital expenditure adjustment for investments was introduced despite recommendations in the evaluation report to the contrary. The recommendation was that the budget approach be retained, as the investment activity of DSOs is sufficient in principle. The only areas where a need for improvement was seen were the instruments of the expansion factor and the investment measures at the 110 kV level. At the same time, it was feared that the introduction of a general capital expenditure adjustment would reinforce the already-mentioned tendency towards favoring capital cost-intensive solutions [17].

3.3.2. Elimination of mandatory parameters

Another key change for the third regulatory period is the elimination of mandatory parameters used to measure the output of the DSOs. On the one hand, efficiency benchmarking showed that not all mandatory parameters help explain the cost differences between DSOs. On the other hand, the mutual dependency of these parameters plays an important role. This can be illustrated by the parameter power line length. Since a greater line length justifies higher costs, there is an incentive to increase the line length. This can lead to an improvement of the DSO's own score in efficiency benchmarking, regardless of whether or not additional lines represent the most efficient integration measure. For this reason, the evaluation report recommended that in the future, the selection of parameters for efficiency benchmarking should be made solely on the basis of qualitative, analytical, engineering or statistical methodologies [17]. This recommendation was followed in the ARegV amendment.

3.3.3. Efficiency bonus

The amendment also introduced a so-called DEA superefficiency bonus scheme, as DSOs with a 100% efficiency rating previously had no incentive to further lower costs. In the newly introduced model, DSOs with an efficiency rating of 100% can receive a mark-up on the revenue cap. The mark-up amounts to a maximum of 5% and is evenly distributed over the regulatory period, so that in practice the efficiency value can amount to a maximum of 101%.

3.3.4. Lowering of interest on equity capital

Furthermore, the Electricity Grid Charges Ordinance stipulates that a permissible rate of interest on equity capital must be determined for each regulatory period [39]. For the second regulatory period this was 9.05% (before taxes) with a permissible equity capital quota of 40%. It will be lowered to 6.91% (before taxes) for new installations in the third regulatory period [41]. The rate of interest on equity capital is determined using a specific method, and it is composed of a basic share and a risk allowance. The basic share is derived from the ten-year average of the current yield on fixed-interest securities. The risk allowance is calculated using a capital asset pricing model, which is intended to determine the appropriate risk/yield ratio [42]. The lowering of interest on equity capital for the third period is supposed to reflect the fall in interest rates for comparable low-risk investments on the capital markets [43].

The use of the pricing model is controversial. From the perspective of grid users − who have to finance the fixed-interest rate through grid charges − the pricing model has not accounted quickly enough for the rapid decrease in interest rates in recent years [43,44]. The DSOs, on the other hand, point to the fact that the interest on equity capital is relatively low by European standards [45].

4. Interview results on the incentivizing effect of the ARegV

4.1. Background on the interview series

The core of the empirical part of this project is a series of interviews conducted with ten representative German DSOs between May and September 2016. The selected DSOs are all large-scale DSOs located in northern, central and southern Germany. On the one hand, their respective grid areas had a relevant degree of renewable energy expansion that caused them to take corresponding integration measures; on the other hand, the selection is meant to cover Germany's geographic spectrum and diverse grid characteristics, thereby spanning a broad range of renewables expansion and associated integration measures. All selected DSOs are thus among the top 30 in Germany with respect to the installed renewable energy capacity. They operate a circuit length of 676,957 km which represents 38% of Germany's distribution grid [4]. Furthermore, the PV capacity installed in the surveyed grids amounts to 44% of the PV capacity installed in Germany until 2015. The wind power and biomass installed capacities are slightly higher at 58% and 47%, respectively.

In order to reflect the spectrum of opinions, our qualitative approach used guided, semi-structured interviews [46]. The aim of the questions was to determine the technical solutions for grid integration and the incentivizing effect of the ARegV on grid planning. The interview partners were instructed to address regulatory issues also from the standpoint of intelligent solutions, used here as an umbrella term for alternatives to conventional grid expansion measures.

The interviews took place during the period when the ARegV amendment was being decided (Cabinet decision of 1 June 2016). This is why the interviews reflect some of the same discussion lines that are present in the evaluation of the ARegV and the ARegV amendment. The following sections present the findings from the interviews and explain how they are connected to the incentive regulation scheme outlined in section 3.

4.2. Financing of grid integration measures is possible

All of the DSOs interviewed stated that they successfully implemented the necessary measures for the integration of renewable energy and were able to finance them [47–56]. These included both conventional grid expansion measures (e.g. increasing line capacities) as well as so-called intelligent measures (e.g. using voltage-regulated local distribution transformers).

If expansion investments are made at the 110 kV level, they are included under the permanently non-controllable cost share $KA_{dnb,0}$. This leads to an increase in the revenue cap within the regulatory period. Until 2012, there had been a time delay of two years, i.e. the revenue cap was not increased until two years after an investment was made. As of 2012, investments at the 110 kV level are already recognized in the year in which they have an impact on revenues. These costs are not subject to efficiency benchmarking for the remainder of the respective regulatory period and are therefore passed on in full to the grid users. In the following regulatory periods, these costs are no longer part of $KA_{dnb,0}$ and are once again subject to efficiency benchmarking.

All additional costs for grid integration measures (capital costs and operating costs) are taken into account according to the budget approach. If framework conditions remain constant, the revenue cap does not change until the following regulatory period, when it is again determined on the basis of the base year. In this context, some of the interview partners also pointed out the financial incentive that this creates for postponing measures until the base year in order to reduce the delay of revenue reimbursements.

In the event that there is a permanent change to the supply responsibility, DSOs may apply for the expansion factor EF_t (see section 3.2.3). The revenue cap is increased within the regulatory period according to this multiplier.

4.3. Lack of incentives for intelligent solutions

In the evaluation report on incentive regulation, it is assumed that the implementation of intelligent measures results in higher operating cost shares than the implementation of conventional grid expansion measures [17]. In the current incentive regulation scheme, however, higher operating cost shares can create financial disadvantages for the DSOs, as only equity capital is subject to interest. All the DSOs with the exception of one commented on this topic.

Three DSOs called for interest payments on operating costs associated with intelligent solutions [48,49,52]. One DSO stated explicitly that due to higher operating costs, intelligent solutions are used to a lesser extent than should actually be the case [52]. Moreover, three other DSOs called for interest payments on operating costs for the use of local distribution transformers in particular [50,51,55]. Furthermore, one DSO cited an example illustrating how it can at times be most cost-efficient to set the tap controllers of all local distribution transformers individually in order to solve potential voltage problems [49]. However, the considerable personnel expenses involved in such a measure would fall under non-interest-bearing operating costs. There is thus a financial incentive in place for capital-intensive, conventional grid expansion measures. The use of voltage-regulated local distribution transformers is also tied to financial disadvantages, as they entail higher operating costs than other solutions for voltage problems (such as laying parallel power lines).

This highlights one of the main areas of conflict arising from the amendment to the ARegV, which is known as the OPEX/CAPEX problem. The associations that represent the DSOs had already demanded during the evaluation process that operating costs (OPEX) be subject to interest. This, they argued, would create a similar incentive to that which applies in the case of capital costs (CAPEX). The Federal Network Agency rejected their demand on the grounds that this would favor solutions with high operating costs without having a dampening effect on capital expenditures [17].

Additionally, one DSO called for long-term safeguards against operating cost risks created by the regulatory scheme [50]. As the operating costs (e.g. personnel or material costs) can increase over time, measures that have higher operating cost shares become a relevant risk factor for the future. The DSOs are unaccustomed to this planning risk, which was already addressed in the course of the ARegV evaluation [17].

Ultimately, this is also indicative of a distribution conflict regarding the financing of the integration of renewable energy. Interest payments on the operating costs associated with the promotion of intelligent solutions would tend to create additional costs for the grid users. These additional costs could be offset by potential cost reductions resulting from the increased use of intelligent operating equipment.

4.4. Intelligent operating equipment is politically overrated

In the interviews it was also emphasized that the widespread use of intelligent operating equipment such as voltage-regulated local distribution transformers is prioritized too much in current energy policy discussions [51,53]. Only one DSO is developing a concept for a rollout. All the other DSOs stressed that the use of voltage-regulated distribution transformers is economically viable only when certain conditions are met. Thus the view of the majority of DSOs is at odds with the claim made in a recent study on the distribution grid by the Federal Ministry for Economic Affairs and Energy (BMWi) that voltage-regulated distribution transformers in combination with feed-in management would represent an alternative to grid expansion at the low-voltage level [28].

Emphasizing the importance of conventional grid expansion, three DSOs have explicitly welcomed the announcement that the budget approach is to be abolished for investments [48,54,56]. The use of intelligent equipment can only mitigate the grid expansion to a certain degree, as conventional grid expansion measures are definitely required in order to meet the existing expansion targets of the German government. Two DSOs therefore called for more favorable interest payments on conventional grid expansion measures [53,55].

This constitutes a major challenge for the regulatory authority, as it is difficult to assess the right balance between conventional grid expansion and the use of intelligent operating systems due to grid-specific conditions. It would be worthwhile to discuss whether more extensive disclosure obligations for the DSOs could bring about the transparency needed for an accurate assessment.

4.5. Adjustment to feed-in management has its limitations

Under the feed-in management scheme, transmission and distribution system operators can curtail the output of power-generating systems in their grid area in order to ensure grid stability. The amendment of the Energy Act in summer 2016 allows DSOs to take feed-in management into account in the planning of grid expansion as well. The idea behind this new regulation is to save grid expansion costs, since curtailing the output of renewable-energy systems during peak periods is cheaper than expanding the electricity grid. Under the new provision, up to 3% of the forecasted annual electricity production per unit of onshore wind and PV in the respective grid area can be curtailed. The owners of distributed renewable energy systems must be compensated for the lost EEG remuneration. The costs of the power curtailment are allocated to electricity customers as permanently non-controllable costs.

A total of five DSOs addressed the amended provision on feed-in management [48–50,53,55]. Three DSOs see the new provision as an improvement compared to the status quo [49,50,55]. However, one of them suggests a different solution [49]: Instead of a flat-rate curtailment of 3% of the power generation of all wind and PV systems in the grid area, it would make more sense to allow for the possibility of a higher power curtailment of individual systems in certain critical grid areas. If this suggestion were to be implemented, it would result in a reduced grid expansion.

However, two DSOs pointed out that grid expansion must keep pace as long as renewable energy capacity is still in its growth phase [48,53]. Only when the renewable energy growth curve approaches its full scope of expansion and levels out will the new provision on feed-in management become effective.

4.6. Improved recognition of research is necessary

Under the ARegV, some of the costs from research and development activities can be added to the revenue cap of the respective calendar year. Eligible under this provision are only state-funded projects; DSOs can apply to have up to 50% of their own funding share credited as permanently non-controllable costs. This can then be directly passed on to the grid users.

A total of three DSOs addressed the issue of offsetting research and development costs. They were in favor of allowing a higher share of these costs to be claimed [51,53,55].

One DSO criticized the focus on individual pilot systems, as this does not allow for extensive field tests [53]. As a consequence, it is difficult to assess the risks of new technologies for widespread use under actual operating conditions.

Another DSO characterized the current form of funding as not effective enough, as it only applies to stated-funded projects and is restricted to 50% of the DSO's own funding share [55]. Accordingly, it would be necessary to broaden the eligibility for research and development activities in distribution grids to include operating costs as well.

4.7. Personal assessments

In this section, the interview partners were asked to give their personal assessments of where they see critical issues with regard to the ongoing transformation of the energy system. Since their answers are personal assessments rather than positions of the DSOs they represent, we deliberately avoid attributing the statements to individual interviewees. In the following, we list points that were addressed by at least two interview partners.

4.7.1. Liberalization

Two interview partners consider the organizational separation of the grids that accompanies the liberalization of the energy markets to be problematic. In light of the energy transition and the associated transformation of the energy system, they see the need for even greater overarching coordination efforts. These, however, are made more difficult by the formal separation.

4.7.2. Questions of fairness

Two of the interview partners see the large number of DSOs and the fragmentation of the grid areas as a critical issue, as this raises questions of fairness. A particular problem was seen in the regional distribution mechanism of grid charges. As the costs of grid expansion are allocated to all of the electricity customers in a particular grid area, the increase in grid charges is greatest in regions with the highest level of renewables expansion and the lowest population density. This means that the costs of the grid expansion are borne primarily by electricity customers living in those regions where the energy transition is taking place.

4.7.3. Political problems

Other interview partners stated explicitly that the problems associated with grid expansion are of a political and social nature, since all of them are solvable from a technical standpoint. There are, for example, acceptance problems relating to grid expansion at the 110 kV level, which typically envisages using overhead power lines. And the cost debate on grid charges is also seen to have an adverse effect on long-term planning security.

5. Discussion

The interviews reflect some of the topics that were discussed in the literature section. The German incentive regulation encompasses elements of the old cost-plus regulation and may therefore be regarded as an evolutionary process. This is now applied to the grid integration of distributed energy systems, as the interviews have shown. For instance, some of the investments are triggered at the 110 kV level. Denoted as “non-controllable costs”, these can be passed on in full to the consumers, resembling a cost-of-service approach. Another topic brought up during the interviews is strategic behavior, which was analyzed by Agrell and Grifell-Tatjé [11]. In this regard, the incentive to postpone investments has been mentioned by some of the interview partners.

A further topic is the interference of the grid integration of distributed energy with the well-known OPEX/CAPEX discussion. Since a number of intelligent measures incur higher operating cost shares and since the interviews took place during the reform of the ARegV (see section 3.3), feedback was particularly active on this point. The request for an interest on OPEX that was made by many interview partners was a reiteration of earlier demands from the DSO lobby groups, which were turned down by the Federal Network Agency. Furthermore, starting with the third regulatory period, all capital costs can be directly passed on to the consumer (see section 3.3.1), even though the Federal Network Agency voted against this measure [17]. Hence, by abandoning the budget approach and adjusting the revenue cap immediately, the German regulation – despite staying an incentive regulation – does in relevant parts have the character of a cost-of-service approach again. The lost efficiency incentive for CAPEX does not only increase the difference in treatment between OPEX and CAPEX exacerbating the tendency toward capital-intensive solutions, but also represents a distributional issue at the expense of the electricity consumer.

With regard to intelligent operating equipment, an important question centered on the actual contribution this new equipment is able to make. Due to rising problems of acceptance related to grid expansion, the expectation from policy makers is that intelligent measures could render large parts of the grid expansion redundant, as a major government report claims [28]. However, almost all of the interviewees disagreed, stressing the specificity of situations and grids where these solutions may be viable. At the same time, this points to the issue of disclosure obligation in Germany, which highlights the problem of asymmetric information between DSOs and the regulatory authority. The new provisions for feed-in management may also be regarded under the same umbrella of reducing grid expansion. But here, too, two interview partners pointed to the rather limited success of the measures as long as growth rates of renewables are high. Another aspect to feed-in management was already mentioned by Ropenus et al. [22]. So far, there is no locational signal as to where to place new distributed capacity and the new regulation does not change that.

Interestingly, the personal assessments of the interview partners focus less on the technical aspects but rather on the "bigger" questions. Some mention the increasing coordination required for the Energy Transition, which is even more difficult under a structure of unbundled generation, transmission and distribution. Many others are mainly concerned with societal issues like fairness of cost distribution and acceptance of grid expansion.

6. Summary and conclusions

This article examines the regulatory aspects related to the integration of decentralized renewable energy in the German distribution grids. It describes in detail the incentive regulation scheme of German distribution system operators (DSOs) and provides an overview of the amendment passed in 2016. It also presents the findings of representative interviews conducted with DSOs on the topic of grid regulation. One of the central questions in these interviews was to what degree intelligent solutions are being implemented and how their use is influenced by the regulatory framework.

The fundamental principle of the Incentive Regulation Ordinance is to regulate the revenues of the DSOs rather than their costs. This budget approach is intended to create an incentive to lower costs during the five-year regulatory periods by allowing the DSOs to keep a portion of their efficiency gains. A further efficiency incentive is implemented in the form of efficiency benchmarking between all German DSOs. The underlying objective of the legislator is to minimize the overall economic costs for the operation of distribution systems. Within the framework of the amendment to the incentive ordinance, the budget approach was eliminated, despite recommendations to the contrary, and replaced by an annual capital expenditure adjustment. In this way, the capital costs are recalculated every year and are fully taken into account for the revenue cap. This has reinforced the trend toward implementing capital-intensive solutions. With regard to efficiency benchmarking, the regulatory authority has now more leeway in the selection of parameters used to measure the output of the DSOs. The amendment also introduced an efficiency bonus, as DSOs with 100% efficiency previously had no incentive to further lower costs.

The first finding of the interview series was that all of the surveyed DSOs were able to implement the necessary measures for the integration of decentralized renewable energy. The revenue of the grid operators is normally adjusted every five years to their specific cost level. In particular cases, the revenue cap can be increased already in the year of the investments (e.g. for investments at the 110 kV level).

Secondly, the DSOs criticized the lack of incentives for intelligent measures, which are often accompanied by higher operating cost shares. At the same time, the statements of DSOs illustrated the limitations of the intelligent approach and emphasized the need for conventional grid expansion. Some of them also explicitly stated the view that the intelligent approach is politically overrated.

Thirdly, while the interviewees welcomed the new provision for energy curtailment in the Energy Act passed in summer 2016, they also pointed out the limitations of the approach. In particular, some of them felt that the provision would not become fully effective until the final renewable energy expansion target is met.

Fourthly, the DSOs saw the necessity for an improved offsetting of research costs. The proposals ranged from removing research costs from efficiency benchmarking to allocating more application funding subsequent to the project funding phase.

Finally, the interview partners provided their personal assessment from their day-to-day business perspective. They pointed out that the energy transition forces them in particular to undertake greater coordination efforts. Furthermore, they see an emerging issue of fairness brought about by the regionally varying grid charges that are magnified by grid expansion. On the whole, they see the problems as more political rather than technical in nature.

In the view of the DSOs, the incentive regulation scheme and its amendment also represent a distribution conflict between grid operators and grid users. This is revealed for instance in the discussions on equity capital interest rates, capital expenditure adjustment, and interest payments on operating costs. The change from the budget approach to the general capital expenditure adjustment, for example, is more advantageous to the DSOs, as the capital costs are thereby directly allocated to grid users. A next step might be to examine to what extent an improved transparency policy could contribute to differentiate between the distribution system operators' own interests and justifiable concerns, in order to develop a more efficient regulatory scheme.

The German experience shows in an exemplary fashion how grid operators can be successfully regulated during the large-scale integration of decentralized renewable energy resources. The electricity grid regulation through incentives could therefore provide inspiration for regulators in countries that aim to significantly expand their wind and photovoltaic capacities. The German regulation formula illustrates the specific elements that can be used to adequately compensate distribution grid operators for significant expansion efforts. However, the German experience also suggests that the specific details of incentive-driven regulation are frequently the subject of political decisions within the context of a distribution conflict between grid operators and grid users. This conflict is universal and is intensified by the accelerated expansion of electricity grids and the related demands for regulation revision. The need to resolve this conflict while taking local conditions into account is one of the greatest challenges faced by regulators.

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Nomenclature

Parameter	*Description, Reference year*
EO_t	Revenue cap, Regulatory year
$KA_{dnb,t}$	Permanently non-controllable cost share, Regulatory year
$KA_{vnb,0}$	Temporarily non-controllable cost share, Base year
$KA_{b,0}$	Controllable cost share, Base year
V_t	Distribution factor for reduction of inefficiency, Regulatory year
VPI_0	Consumer price overall index, Base year
VPI_t	Consumer price overall index, Regulatory year
PF_t	General sectoral productivity factor, Regulatory year
EF_t	Expansion factor, Regulatory year
Q_t	Quality element, Regulatory year
VK_0	Volatile cost share, Base year

VK_t Volatile cost share, Regulatory year
S_t Account balance from previous period, Regulatory year

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