Electricity Distribution System Operators
1 January 2019 - 31 December 2023
Regulatory Regime for the Fourth Regulatory Period

December 2018

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1. Introduction

This document describes the regulatory regime that applies to electricity distribution system operators in Austria during the fourth regulatory period. We build on the regime for the third period but we adjust it for the fourth period as follows:

- We have conducted a new cost audit, based on which we re-examine the allowed costs and undertake a new efficiency benchmark, including revised output parameters.
- We shorten the period for eliminating individual inefficiencies (realisation period) to one-and-a-half regulatory periods (previously: two periods) and raise the efficiency floor.
  This is meant to strengthen the force of efficiency targets for electricity distribution system operators and to avoid inflated allowed costs at the beginning of a regulatory period. If efficiency targets were spread over two entire regulatory periods, the pressure to improve would be too weak.
- We re-calculate the operating cost factor. This is necessary due to changes in the operators' cost structures.
- We replace the investment factor by direct CAPEX compensation.
  Regulated companies are reimbursed for their CAPEX through cost of capital for assets they actually hold and through depreciation. They can thus be sure that their investments are covered. In addition, we achieve allocative efficiency even during the regulatory period as the dead band inherent in an investment factor is eliminated.
- We introduce efficiency-driven capital returns (WACC) for system operators.
  Previously, only efficient system operators could achieve the WACC specified by E-Control in accordance with section 60 Electricity Act 2010. The new regime grants this average WACC to system operators with average efficiency scores, while more efficient operators receive higher WACCs and less efficient operators receive lower ones.
- We exempt depreciation from efficiency targets.
  The returns that system operators (and their owners) can generate depend on their relative efficiency, but depreciation does not play into this remuneration. Therefore, depreciation is simply passed through, thereby ensuring that investments are covered.
- We introduce a mark-up on the WACC (cf. section 60 Electricity Act 2010) for investments made from 2019 onwards to promote investments.
- We eliminate the mechanism for smart metering OPEX compensation from the third regulatory period (OPEX Cost-Plus Regulation) and instead introduce unit costs, thereby providing an incentive.
- We update several other parameters, such as the WACC and X-gen.

Under a long-term incentive regime that applies to all companies equally and remains stable for several years, there is only limited scope for taking into account individual companies' characteristics.[1] We therefore explicitly make mention of the fact that several elements, such as the network operator price index, are based on average costs (in line with section 59 Electricity Act 2010).[2]

The principles presented here are first applied during the cost audit conducted in 2018 (i.e. the one that serves as a basis for 2019 system charges).

[1] A regulatory model, simply by virtue of being a model, is necessarily an abstraction of reality.

[2] *Elektrizitätswirtschafts- und –organisationsgesetz* (Electricity Act) 2010, Federal Law Gazette (FLG) I no 110/2010 as amended by FLG I no. 108/2017.

Please note that this document presents the basic building blocks of the regulatory regime and that we have simplified the formal descriptions for the sake of readability.

The regime as presented here applies to all Austrian electricity distribution system operators that delivered more than 50 GWh to customers in 2008 and it is valid for the duration of the fourth regulatory period. It is without prejudice to the features of regimes that will apply in future regulatory periods. Also, the present document relies on the relevant legal provisions in their currently applicable version (i.e. the Electricity Act 2010 and the E-Control Act).[3] Should the legal framework be amended, this could trigger changes to the regulatory regime (even in the course of the regulatory period).

The regulatory regime as presented in this paper is the result of a stakeholder involvement process between E-Control, the industry association Oesterreichs Energie, representatives of individual companies and the statutory parties listed in section 48 Electricity Act 2010 (i.e. the Federal Chamber of Labour and the Federal Economic Chamber). This process included a series of discussions and the exchange of studies, materials for calculations and position papers and lasted from March 2017 until summer 2018. Once we had consolidated the preliminary results of this process, we submitted them to the stakeholders in summer 2018 and asked for their reactions within an adequate deadline. The materials that we made available included the minutes of all high-level and expert meetings with industry representatives and statutory parties, along with the studies that had been put forward and the presentations that had been held.

Many system operators and industry representatives and the statutory parties submitted their reactions in September 2018. We have analysed these reactions and divided them into two categories: one, comments relating to individual companies; and two, generally applicable comments. While the former are addressed in the relevant official decisions, the latter are discussed below.

2. Incentive regulation principles

A natural monopoly incentive regulation regime that is stable in the long term should pursue a number of – sometimes conflicting – objectives:

> Efficient behaviour on the part of the regulated companies in the interest of optimal economic outcomes;

> Consumer protection;

> Viability of and planning certainty for regulated companies;

> Investment and innovation security for regulated companies (this overlaps with the previous item);

> Security of supply and quality of service;

> Transparency;

> Fair treatment of regulated companies;

> Low direct costs of regulation;

> A stable regulatory regime that is accepted by all relevant stakeholder groups (customers, employees, system owners, etc.); and

> A legally robust regime.

If a company is to act in a *productively* efficient way, i.e. if it is to endeavour to produce goods and render services at the lowest possible inputs (costs), it must have some kind of incentive to do so.

[3] *Energie-Control-Gesetz* (E-Control Act), FLG I no. 110/2010 as amended by FLG I no. 174/2013.

Productive efficiency must be rewarded, at least for a certain period of time. Therefore, during this period of time, we must accept an *allocatively* inefficient situation.

On the one hand, excessive *allocative* inefficiency can be against consumer interests and consequently pose a threat to political acceptance of the regulatory regime. On the other hand, any ex-post intervention in the regime for the purpose of skimming off profits that are regarded as inappropriate contradict the goal of providing incentives for *productive* efficiency.

Regulation must ensure that the regulated companies remain financially viable. This can conflict with the objective of *productive* efficiency, since it limits the most effective sanction available in a competitive economy, i.e. the possibility of a company being driven off the market. Consequently, economics literature discusses the extent to which the regulator may or, in view of the political environment, must allow a *soft budget constraint* in the case of regulated companies.

Transparency of the regulatory regime needs to be guaranteed to create acceptance on the part of companies and consumers. To achieve this, the information based on which decisions are taken must be disclosed in a clear and comprehensible manner. However, this does not mean that regulated companies' comments and wishes should be automatically accepted.

Transparency is closely connected to planning certainty: regulated companies must know the framework at the beginning of the regulatory period. Still, changes to the regime must be possible. To consolidate these two, the regulatory authority must continuously evaluate the regime. If it detects room for improvement, the regulatory regime should be amended, and the amendments should come into force at the beginning of the next regulatory period.

Fairness towards regulated companies means avoiding preferential treatment of some companies over others and not imposing excessive burdens (i.e. targets which go beyond the companies' efficiency potential) on any one party. However, it also means factoring in productive efficiency and being cautious in applying a soft budget constraint: if companies are granted too much time to reach efficiency targets, fairness for consumers is skewed and the regime can no longer simulate competitive pressure in the regulated sector.

Regulation also needs to balance the various objectives in such a way as to ensure political acceptance and stability for the entire regulatory period.

Regulation can be based on annual cost audits, as in the past, but this means much effort for both the regulated companies and the regulator. Alternatively, regular but not annual cost audits can take place under a stable, long-term model. We prefer the latter approach as it minimises the direct costs of regulation. In between cost audits, grid charges[4] evolve in accordance with a formula that uses parameters which are known in advance. To ensure that the charges do not diverge too far from the underlying cost trends, the period from one cost audit to the next should not be too long.

The below chapters explain the regime for the fourth regulatory period in greater detail.

3. Scope of application and length of the regulatory period

The regulatory regime presented in this document applies to all operators of electricity distribution systems in Austria that transported more than 50 GWh through their networks in 2008 (cf. section 48(1) Electricity Act 2010). A total of 38 companies meet this condition (s. annex 1 in chapter 17).

When setting the length of a regulatory period, we must take into account several effects. As described above in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**, incentives for productive efficiency are created by temporarily decoupling the allowed costs from the actual costs (revenues). The degree to which such incentives are effective depends on how long this decoupling

[4] This document uses the terms 'tariffs', 'charges' and 'rates' synonymously.

is maintained for, i.e. on the length of the regulatory period.[5] By decoupling, the regime intentionally tolerates a temporary situation of allocative inefficiency so as to generate incentives for productive efficiency. Choosing the length of the regulatory period is key: if it is too short, the incentive for productive efficiency might not be strong enough; if it is too long, consumers might overestimate and companies might underestimate the potential for cost reduction. This latter effect grows the longer the period lasts.

Current regulatory practice usually provides for regulatory periods between three and five years. In Austria, both the regulatory authority and the regulated companies have gained extensive experience with incentive regulation. It therefore appears reasonable to maintain the 5-year period used previously.

Economic literature warns of the so-called ratchet effect;[6] to keep this to a minimum, the regime provides for ongoing benchmarking. 'Ongoing' in this context means that the efficiency benchmark is performed before each regulatory period, so that the resulting targets are only in effect for one regulatory period.

With such a regime, cost data must be adjusted and corrected before they can be transformed into allowed costs and used in the benchmarking exercise, so as to avoid operators strategically shifting cost items (e.g. in the areas of maintenance, staff or similar). Particularly when reviewing the regulated companies' internal cost allocation, especially in the case of overheads and payments for internal and external services, strict cost auditing principles must apply and checks must be conducted to verify whether both the grounds for payment and the amount paid were reasonable.

4. Allowed costs

In general, we use the most recent available figures in our cost audits and in establishing the volumes that were transported. However, the cost audits we conduct require significant time and effort, both on our end and on the companies'. Also, regulated companies should have sufficient time to submit comments on proposed changes in the regulatory regime (including a new efficiency benchmark) and on the official decisions on their allowed costs. And finally, we cannot set targets based on the most recent figures of most companies; rather, we need figures from all companies. For these reasons, we do not audit the costs of the most recent full business year (2017) but rather those of the previous year (2016).

More precisely, what counts is the balance sheet date as defined in section 201 *Unternehmensgesetzbuch* (Corporate Code): for each company, we use the data from the annual financial statement whose balance sheet date is in 2016.

There are exceptions to this rule. For some cost items (e.g. non-controllable costs and the input parameters for calculating the expansion factors), we use the most recent figures available so as to minimise the systemic time lag. Any negative effects resulting from the remaining time lag are softened (cf. chapter 11.3).

4.1. Audited 2016 costs

In line with the above, the fourth regulatory period is based on the total costs (OPEX and CAPEX) for the 2016 business year (K_{2016}) as audited by the regulatory authority. Our decisions on whether to allow individual cost items or not follow the general principles in section 59 Electricity Act 2010. To be clear: we use financial accounting data (i.e. balance sheet figures) as it would make no sense to calculate allowed costs based on budget figures (cf. the explanatory notes on section 59(1) and

[5] Please note that for yardstick regulation, the length of a regulatory period is not an issue, since it completely decouples allowed from actual costs (even in the initial year), while incentive regulation does so only for a defined period of time.
[6] The term "ratchet effect" designates the risk of exaggerated costs being stated for the audit year, resulting in excessive allowed cost at the beginning of the regulatory period (cf. Rodgarkia-Dara A., 2007, *Ratchet Effect: Theorie, Lösungsansätze und internationale Erfahrungen* (Ratchet effect: theory, solutions and international experience), E-Control Working Paper 18, 1-70).

(4) Electricity Act 2010). We also run plausibility checks of the 2016 accounts against developments in previous years and we normalise the figures accordingly. This way, we avoid looking at the figures for balance sheet date only, we work against any strategic shifting of cost items into the 'snapshot' year and we take into account any one-off effects.[7]

In accordance with section 59(6) Electricity Act 2010, the cost audit differentiates between the operational costs that are "within the company's control" (i.e. controllable costs) and those that are "beyond the company's control" (i.e. non-controllable costs); added together, they make up the full OPEX for 2016 ($OPEX_{2016}$). This distinction is necessary because the controllable costs are subject to the general and individual targets specified in section 59(2) Electricity Act 2010 and to the network operator price index. The non-controllable costs (*nbK*), on the other hand, are not subject to any targets. They are audited based on the most recent available figures and passed through without any mark-ups or mark-downs. In other words, they are simply added in the regulatory formula (s. chapter 14). This differentiation is also relevant for dealing with the systemic time lag (s. chapter 11.3).

Section 59(6) Electricity Act 2010 lists the following as non-controllable DSO costs in a particular year (nbK_t):

> the costs for the use of directly or indirectly connected systems in Austria (e.g. upstream network costs);
> community levies for the use of public land;
> the costs for covering system losses; this must be done by way of a transparent and non-discriminatory procurement procedure, and the costs correspond to the component of the grid charges for system losses;
> the costs arising from statutory rules to be followed in cases of *Ausgliederung* (a type of demerger under Austrian law) which existed on the merits of the situation at the time of full opening of the electricity market on 1 October 2001.

Starting with the fourth regulatory period, we handle OPEX and CAPEX in different ways.

4.2. Controllable OPEX

As during previous regulatory periods, a budget that covers a company's operational expenditure for the entire duration of the regulatory period is set up. We use dedicated operating cost factors (cf. chapter 11.1) to also account for any changes to the company's mandate that occur during the period. Inflation, which lies beyond the control of the DSOs, is factored in by the network operator price index. At the same time, each company's individual efficiency target is identified and combined with the general productivity growth rate into the overall efficiency target.

We calculate the allowed OPEX by applying the network operator price index (NPI, s. chapter 8) and the general productivity growth rate (X-gen, s. chapter 5) to the controllable OPEX 2016, thereby mapping two opposite effects: the NPI reflects exogenous price increases, while X-gen accounts for sector-specific productivity growth.

$$OPEX_{2018}^{Pfad} = (OPEX_{2016} - nbK_{2016}) \times \prod_{t=2017}^{2018} [(1 + \Delta NPI_t) \times (1 - Xgen_{4.Periode})]$$ [8]

For companies whose financial year does not coincide with the calendar year, the calculation is adjusted accordingly.

[7] Examples of one-off effects include unanticipated cost increases resulting from natural disasters (of course, normal reinvestment in grid infrastructure is not part of this category).

[8] In English:
$OPEX_{2018}^{Allowed} = (OPEX_{2016} - NonControllableCosts_{2016}) \times \prod_{t=201}^{2018} [(1 + \Delta NetworkOperatorPriceIndex_t) \times (1 - Xgen_{4thPeriod})]$

The allowed 2018 OPEX are the basis for the 2019 grid charges. Chapter **Fehler! Verweisquelle konnte nicht gefunden werden.** describes the targets and network operator price index that we use to calculate these allowed 2019 OPEX.

$$OPEX_{2019}^{Basis\ Entgelte} = OPEX_{2018}^{Pfad} \times (1 + \Delta NPI_{2019}) \times (1 - ZV_{4.Periode}) \quad 9$$

4.3. CAPEX

With the start of the fourth regulatory period, we introduce a fundamental change to how capital cost is handled in the regulatory regime. As opposed to OPEX, for which companies are basically granted an overall budget to spend along the entire regulatory period, CAPEX are tracked and compensated as they arise. Roughly speaking, capital cost consists of depreciation and the cost of capital (opportunity cost) for the regulatory asset base.

We introduce the concept of an individual WACC which we grant for assets acquired up to a certain cut-off date; this individual WACC is designed to incentivise efficiency.

4.3.1. Calculating the individual WACC

For the fourth regulatory period, we use each company's individual efficiency score, out of the TOTEX benchmarking exercise described in chapter 6, to derive its individual WACC.

First, we calculate the average efficiency score across all companies, i.e. the arithmetic mean of all benchmarked system operators, and we apply an efficiency floor of 80%. A company with an average efficiency score receives a WACC of 4.88% (before taxation, s. chapter 9) on the regulatory asset base (cf. chapter 10). If a company is more/less efficient than the average, its WACC adjusted by a maximum of +/- 0.5 percentage points.

To ensure that the RAB of Austrian electricity distribution system operators generates an average return of 4.88%, we offset above-average and below-average efficiencies against each other. We use an adjustment factor k1 for this purpose. It is designed to make sure that the WACC mechanism is cost neutral, i.e. so that the total additional returns granted to particularly efficient companies are exactly offset by the total cuts imposed on companies with below-average efficiency scores.

Overall, the WACC for an above- or below-average company *i* is calculated as follows:

$$WACC_{überdurchschnittlich;i}^{Effizienz} = 4{,}88\% + \frac{0{,}5\% \times k1}{(100\% - \emptyset Effizienz)} \times (Effizienzwert_i - \emptyset Effizienz)$$
$$WACC_{unterdurchschnittlich;i}^{Effizienz} = 4{,}88\% - \frac{0{,}5\%}{(\emptyset Effizienz - 80\%)} \times (\emptyset Effizienz - Effizienzwert_i) \quad 10$$

This means there are no additional costs from this incentive mechanism. For the fourth regulatory period, the above calculation results in an adjustment factor k1 of 0.1148.

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[9] In English:
$OPEX_{2019}^{BasisForCharge} = OPEX_{2018}^{Allowed} \times (1 + \Delta NetworkOperatorPriceIndex_{2019}) \times (1 - OverallEfficiencyTarget_{4thPeriod})$

[10] In English:
$WACC_{AboveAverage;i}^{Efficiency} = 4.88\% + \frac{0.5\% \times k1}{(100\% - \emptyset Efficiency)} \times (EffiziencyScore_i - \emptyset Efficiency)$
$WACC_{BelowAverage;i}^{Efficiency} = 4.88\% - \frac{0.5\%}{(\emptyset Efficiency - 80\%)} \times (\emptyset Efficiency - EfficiencyScore_i)$

The return on equity for Austrian electricity distribution system operators is 6.90%-8.29%.[11] The average is 8.15% before taxation. Once the mechanism has been in place for some time, we will evaluate whether it sufficiently incentivises companies to improve their efficiency.

4.3.2. Applying the individual WACC

We apply each company's individual WACC to the depreciated book value of its RAB up to 2016. A uniform 4.88% WACC applies to all investments made in 2017 and 2018 (minus customer prepayments). We choose a uniform rate for these years because there is no annual efficiency benchmark, i.e. until the next benchmark is carried out and can be taken into account in future regulatory periods, we must assume the same (average) efficiency for all investments. For investments from 2019 forward, a mark-up raises this rate to 5.20%. This mark-up is meant to promote investments, i.e. it goes beyond the appropriate WACC prescribed by section 60 Electricity Act 2010. Depreciation is passed through without any mark-downs or other changes, i.e. we minimise the risk exposure for system operators by guaranteeing that their investments are covered through the grid charges.

Applying the individual WACC to the RAB and using the book values from year t-2, we arrive at the following formula for the CAPEX to be included in 2019 grid charges:

$$\begin{aligned} &Kapitalkostenabgleich_{2019} \\ &\quad = AfA_{2017} + RAB^{2017}_{Vermögen\ bis\ 2016} \times WACC\_Eff + RAB^{2017}_{Vermögen\ ab\ 2017} \times 4{,}88\% \end{aligned} \tag{12}$$

For the years from 2020 onwards:

$$\begin{aligned} &Kapitalkostenabgleich_{2020} \\ &\quad = AfA_{2018} + RAB^{2018}_{Vermögen\ bis\ 2016} \times WACC\_Eff + RAB^{2018}_{Vermögen\ ab\ 2017} \times 4{,}88\% \\ &Kapitalkostenabgleich_{2021} \\ &\quad = AfA_{2019} + RAB^{2019}_{Vermögen\ bis\ 2016} \times WACC\_Eff + RAB^{2019}_{Vermögen\ ab\ 2017} \times 4{,}88\% \\ &\qquad + RAB^{2019}_{Vermögen\ ab\ 2019} \times 5{,}20\% \end{aligned} \tag{13}$$

5. General productivity growth rate (X-gen)

The first and second regulatory periods featured a general productivity rate of 1.95% p.a.; for the third period, we lowered this rate to 1.25%. During the stakeholder involvement process ahead of the fourth regulatory period, the regulated companies proposed further lowering X-gen, this time to 0%. To support their position, they submitted a study commissioned by the Association of Austrian

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[11] $Rendite^{EK} = \frac{WACC\_EFF \quad {}^{Zins} \times FK^{Anteil}}{EK^{Anteil}}$

In English:

$$Equity^{Return} = \frac{WACCIndividual - Debt^{Return} \times Debt^{Share}}{Equity^{Shar}}$$

[12] In English:
$DirectCAPEXCompensation_{2019} = Depreciation_{2017} + RAB^{2017}_{AssetsUpTo2016} \times WACCIndividual + RAB^{2017}_{AssetsFrom2017} \times 4.88\%$

[13] In English:
$DirectCAPEXCompensation_{2020} = Depreciation_{2018} + RAB^{2018}_{AssetsUpTo2016} \times WACCIndividual + RAB^{2018}_{AssetsFrom2017} \times 4.88\%$

$$DirectCAPEXCompensation_{2021} = Depreciation_{2019} + RAB^{2019}_{AssetsUpTo2016} \times WACCIndividual + RAB^{2019}_{AssetsFrom2017} \times 4.88\%$$

$$+RAB^{2019}_{AssetsFrom2019} \times 5.20\%$$

Electricity Companies, Oesterreichs Energie (Gugler/Liebensteiner 2017[14] and Gugler/Liebensteiner 2018a[15]). This study uses panel data (i.e. cross-sectional company data over several years) to arrive at an econometric estimate of X-gen. We could not fully confirm the data used as they were not corrected for other operational income generated by the companies, the most recent data used is from 2015, and the data basis is missing considerable amounts of values. For this reason, we commissioned a study ourselves (WIK-Consult 2018[16]) and undertook a separate data collection exercise. For this, we extracted data submitted by the regulated companies as part of our annual data collection, for the years 2002-2016, and we isolated data for the companies that are subject to the regulatory regime (i.e. electricity distribution system operators that transported more than 50 GWh through their networks in 2008). The data extracted included the components of the companies' operational expenditure and potential cost drivers such as real line length, peak load, metering points, customer and load density, number of employees dedicated to grid issues etc. We double-checked these data with the companies and corrected them for any exceptional effects that are not related to productivity (e.g. costs of the upstream grid, costs for covering grid losses, community levies, the regulatory account or extraordinary provisions for personnel costs in individual years). The resulting set of confirmed data was made available to the industry consultant (Gugler/Liebensteiner), the consultant of the Austrian Economic Chamber (Swiss Economics), and the consultant of the Federal Chamber of Labour (Frontier Economics) so that they could run their own analyses. By making sure that all studies and opinions could be based on the same data, we hoped to be able to integrate them all to arrive at a solid estimate of the general productivity growth rate.

At a workshop with E-Control, Oesterreichs Energie, company representatives, the Federal Chamber of Labour and the Austrian Economic Chamber on 6 June 2018, we invited the consultants (Gugler/Liebensteiner, WIK-Consult, Frontier Economics and Swiss Economics) to present their results. Swiss Economics (2018a[17]) did not calculate X-gen values for the fourth regulatory period but instead undertook a descriptive data analysis. Gugler/Liebensteiner (2018b[18]), Frontier Economics (2018a[19]) and WIK-Consult (2018) ran in-depth empirical analyses. After the workshop, the following further studies were submitted: Swiss Economics 2018b,[20] Frontier Economics 2018b,[21] Gugler/Liebensteiner 2018c,[22] Gugler/Liebensteiner 2018d,[23] Gugler/Liebensteiner

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[14] K. Gugler, M. Liebensteiner (2017), *Empirische Schätzung des Produktivitätswachstums und Berechnung des generellen X-Faktors im österreichischen Stromverteilnetz* (Empirical estimate of the productivity rate and calculation of the general productivity rate for the Austrian electricity distribution network), study commissioned by Oesterreichs Energie, 5 July 2017.

[15] K. Gugler, M. Liebensteiner (2018a), *Empirische Schätzung des Produktivitätswachstums und Berechnung des generellen X-Faktors im österreichischen Stromverteilnetz*, (Empirical estimate of the productivity rate and calculation of the general productivity rate for the Austrian electricity distribution network), study commissioned by Oesterreichs Energie, 21 March 2018.

[16] WIK-Consult GmbH (2018), *Ermittlung des generellen Faktorproduktivitätsfortschritts für Stromverteilernetzbetreiber in Österreich im Zuge der vierten Regulierungsperiode* (Calculating the general productivity growth for electricity Austrian distribution system operators during the fourth regulatory period), study commissioned by E-Control, 26 June 2018.

[17] Swiss Economics (2018a), *Zwischenresultate Xgen* (Intermediate results on X-gen), study commissioned by the Austrian Economic Chamber, 6 June 2018.

[18] K. Gugler, M. Liebensteiner (2018b), *Empirische Schätzung des Produktivitätswachstums im österreichischen Stromverteilnetz* (Empirical estimate of the productivity growth for the Austrian electricity distribution network), study commissioned by Oesterreichs Energie, 6 June 2018.

[19] Frontier Economics (2018a), *Generelle Produktivitätsvorgabe* (General productivity rate), study commissioned by the Federal Chamber of Labour, 6 June 2018.

[20] Swiss Economics (2018b), *Regulierungssystematik für die vierte Regulierungsperiode VNB Strom* (The regulatory regime for electricity DSOs during the fourth regulatory period), study commissioned by the Austrian Economic Chamber, July 2018.

[21] Frontier Economics (2018b), *Gutachten zur Anreizregulierung von Strom-VNB in Österreich* (Incentive regulation of electricity DSOs in Austria), study commissioned by the Federal Chamber of Labour, August 2018.

[22] K. Gugler, M. Liebensteiner (2018c), *Stellungnahme zu den Präsentationen zum X-Gen Stromverteilnetz am 6.6.2018* (Reply to the presentations about the X-gen for the electricity distribution network held on 6 June 2018), study commissioned by Oesterreichs Energie, 19 June 2018.

[23] K. Gugler, M. Liebensteiner (2018d), *Kurzstellungnahme zu ‚Vorläufige Regulierungssystematik für die vierte Regulierungsperiode der Stromverteilernetzbetreiber 1. Jänner 2019 – 31. Dezember 2023' der E-Control Austria vom*

2018e[24] and Oxera 2017.[25] All studies that were submitted as part of the process are summarised and discussed below.

Swiss Economics – studies commissioned by the Austrian Economic Chamber

Swiss Economics 2018a and 2018b analyse the industry-commissioned study Gugler/Liebensteiner 2018a and undertake a graphical analysis of our data set. They find that Gugler/Liebensteiner 2018a have chosen a similar approach as for gas last year.

According to Swiss Economics, it is not appropriate to use financial-accounting-based TOTEX because the regulatory regime for the fourth period no longer subjects CAPEX to any mark-down (cf. chapter 4.3). Also, they advocate for the estimation equation to use real costs instead of nominal costs, given that company returns depend on volume: nominal estimations that control for changes in input prices are problematic because the input price for labour (costs per employee) is erratic and does not reflect controlled operational processes. As in benchmarking, an outlier analysis should be conducted. Fixed effects models should also be tested. And in terms of data, the reference period should correspond to the period during which incentive regulation has been applied and should not be changed for each regulatory period. They caution against adjusting the reference period so that it fits individual interests.

The Swiss Economics graphical analyses of our data set shows a continuous rise in real standardised CAPEX and an erratic trend for real OPEX, resulting in a steady growth of real standardised TOTEX. The cost curve for regulated companies is steeper than that for general price developments, with particularly pronounced increases in the audit years for the regulatory periods. At the same time, the growth of the cost driver aggregate has been slower than that of standardised TOTEX. This indicates that overall, system operators hardly realised efficiency improvements in terms of the outputs delivered to customers.

Swiss Economics 2018a and 2018b conclude that an OPEX-driven calculation of X-gen should result in a positive value. While they consider a general productivity rate below previous levels to be plausible, they exclude a value of 0: the evident general productivity growth does not stop at the Austrian distribution system operators.

Frontier Economics – studies commissioned by the Federal Chamber of Labour

Frontier Economics 2018a and 2018b analyse both nominal and real OPEX and TOTEX. They identify three key decisions to make: (i) using nominal or real cost; (ii) choosing TOTEX or OPEX to estimate the cost function; and (iii) finding an adequate reference period. After conducting several estimates, they advocate for OPEX. Their method uses a cost function with linear and squared time trends, a fixed effects model and a restriction to constant returns to scale. Given that no full input price set (i.e. including prices for labour, capital and intermediate consumption) is available, they do not use factor prices. As a second-best solution, they use real costs. According to the authors, only using nominal costs without the factor prices would mean ignoring increases in input prices and therefore underestimate productivity growth. Frontier Economics 2018a and 2018b also detect a pronounced OPEX-CAPEX shift in the data.

19.07.2018 (Brief reaction to the draft regulatory regime for the fourth regulatory period for electricity DSOs for the period from 1 January 2019 to 31 December 2019 by E-Control of 19 July 2018), study commissioned by Oesterreichs Energie, 14 August 2018.

[24] K. Gugler, M. Liebensteiner (2018e) *Stellungnahme zu „Regulierungssystematik für die vierte Regulierungsperiode VNB Strom (Gutachten im Auftrag der Wirtschaftskammer Österreich (WKÖ), Swiss Economics)* (Reply to the study commissioned to Swiss Economics by the Austrian Economic Chamber on the regulatory regime for the fourth regulatory period for electricity DSOs), study commissioned by Oesterreichs Energie, 1 October 2018.

[25] Oxera (2017), *Bestimmung des Produktivitätsfaktors für österreichische Stromverteilnetze* (Determining the general productivity growth rate for Austrian electricity distribution networks), study commissioned by Oesterreichs Energie, 13 April 2017.

They conclude that an X-gen of 0 would contradict the basic tenet of a market economy. Employing OPEX estimations based on nominal and real costs, they recommend a general productivity growth rate of between 0.3 and 2.6%. The choice of OPEX over TOTEX reflects the general decision for the regime to apply X-gen to OPEX only (cf. chapter 4.3). However, using real OPEX only would overestimate the general productivity growth. They also point out that an OPEX cost driver analysis would be needed.

Frontier Economics conclude that X-gen should be above 0. Both ends of the recommended interval suffer from distortions, which is why a value towards the middle would be more appropriate; in fact, insecurities in empirical estimates point towards the lower half.

Gugler/Liebensteiner – study commissioned by Oesterreichs Energie

Gugler/Liebensteiner 2018b start with the premise that productivity improvements decrease over time, i.e. that X-gen should converge on 0 in the long term. Their estimates use the data made available by us and data they have collected themselves; they employ capital cost as recorded in the companies' financial accounts and define outputs along the lines we have specified.

Data on factor prices are, however, limited (missing values and considerable variations due to outsourcing). Gugler/Liebensteiner estimate their cost function including factor prices but without taking into consideration firm-fixed effects. The dependent variables are both TOTEX and OPEX. They deflate both the factor prices used in their regression and the costs with the network operator price index (NPI). Deflating costs without correcting for input prices would lead to an overestimation of TFP growth.

The regression analysis leads Gugler/Liebensteiner to conclude that (i) the potential for technological progress in the electricity distribution sector has been fully exploited; (ii) the time trend includes not only a frontier shift but also a catch-up effect; and (iii) an X-gen of 0% is thus appropriate.

WIK-Consult – study commissioned by E-Control

WIK-Consult 2018 maintain that OPEX should be the dependent variable because they are subject to X-gen (cf. chapter 4.3). Factor prices would be the preferred option for the OLS estimate (cf. the arguments brought by Gugler/Liebensteiner), but since they are not available (or data quality is insufficient), real costs are calculated by deflating the OPEX with the NPI. Before getting into the OLS estimate, they conduct an array of tests to identify the panel structure (cf. the arguments by Swiss Economics) and a dynamic cost driver analysis (cf. Frontier Economics).

WIK-Consult's preferred specification features firm-fixed effects and deflated OPEX (excluding factor prices because of insufficient data quality and data gaps). It results in a productivity growth rate of 1.72% p.a., with a 95% confidence interval for a range of 1.10-2.35% (cf. WIK-Consult, table 4-2, specification 1a).

They also run a Malmquist index calculation, enabling them to distinguish between frontier shift and catch-up effect (cf. the discussion of Frontier Economics and Gugler/Liebensteiner above). This leads them to estimate TFP growth at 2.22-2.36%.

In further analyses, WIK-Consult consider sensitivities with and without outliers, corrections for the capital stock and a squared time trend. The results of the sensitivity analysis in the main specification support a productivity rate of 1.7% or above. The corresponding recommended interval is 1.7%-2.3% p.a.

Gugler/Liebensteiner reply to the other consultants

Following the workshop on 6 June 2018, Gugler/Liebensteiner handed in a reply to the presentations held by the other consultants (Gugler/Liebensteiner 2018c). They criticise the other consultants' arguments and supply a number of new calculations, employing different OPEX and

TOTEX data sets, considering a squared time trend, and including factor prices (supplying also a discussion of Shephard's Lemma to underline that this is not only the first-best but indeed the only adequate solution). Gugler/Liebensteiner conclude that TFP growth rates of -0.83% for TOTEX and -0.08% for OPEX, statistically not different from 0, would be appropriate.

Brief reaction to the draft regulatory regime by Gugler/Liebensteiner

During the consultation of the draft regulatory regime, Gugler/Liebensteiner handed in a brief reaction relating to X-gen, then proposed by us at 0.785% p.a. (Gugler/Liebensteiner 2018d). They put forward the following arguments: (i) the data set used was corrected for other operational revenue; (ii) the graphical analysis conducted by Swiss Economics 2018a does not lend itself to scientifically deriving X-gen; (iii) the upper end of the range calculated by Frontier Economics 2018a is distorted; (iv) the exclusion of firm-fixed effects is rooted in the results of the regression; (v) the lack of a factor price for intermediate consumption and the assumption that the corresponding markets are competitive cannot be used as arguments against including input prices; (vi) the estimate should include a squared time trend; and (vii) deflating costs without taking into consideration factor prices leads to an overestimation of productivity growth.

Gugler/Liebensteiner reply to the Swiss Economics study commissioned by the Austrian Economic Chamber

Gugler/Liebensteiner also submitted a reply to Swiss Economics 2018b (Gugler/Liebensteiner 2018e). In this reply, they argue that (i) the data set used was corrected to ensure that the factor price for labour would be adequately reflected; (ii) correcting for outliers does not lead to higher significance levels; (iii) statements based on purely graphical analysis must be rejected; (iv) it is essential that individual factor prices for each company be used; (v) the standardised capital cost data provided by E-Control are distorted; (vi) the 2010-2015 reference period strikes a balance between the goals to have a stable basis and to use recent data; (vii) estimating costs without using input prices necessarily distorts the calculated productivity growth; (viii) having to integrate volatile renewables (with high investment cost but no increase in outputs) negatively impacts productivity; and (ix) there is no scientific basis for ex-post corrections of estimated total factor productivity in network industries.

Oxera study commissioned by Oesterreichs Energie

Oxera, commissioned by Oesterreichs Energie, delivered yet another study on X-gen for Austrian electricity DSOs (Oxera 2017). Applying the Törnqvist method to publicly available sector data, Oxera refer to a variety of reference periods to calculate production value and added value. They conclude that X-gen could be slightly positive or slightly negative, with a preference for 0.

However, their approach suffers from several data issues: the data used refer to the energy supply sector in general, i.e. electricity, gas, heating and cooling. Consequently, data for electricity DSOs alone were not at the authors' disposal. In addition, it is unclear whether the output indices were indeed deflated with the price index for the electricity industry; and there is no consideration of the utilisation degree of production factors, resulting in a negative productivity rate for 2009 (during the economic and financial crisis). Oxera 2017 conclude that the results might not be as robust as they would wish.

Given these issues, we cannot be sure that the results presented by Oxera 2017 indeed refer to the total factor productivity growth of electricity distribution systems in Austria. We therefore exclude this study from our considerations.

E-Control reaction and consideration of the studies presented

i) OPEX vs TOTEX

WIK-Consult 2018 discuss the question of OPEX vs TOTEX in detail. They voice a preference for OPEX given that the Austrian regulatory regime does not subject CAPEX to X-gen. This result is supported by an extensive cost driver analysis (something not done for gas in the previous year).

We therefore consider using OPEX to be appropriate.

ii) Specification of the cost function

WIK-Consult also analyse the issue of first-best vs second-best solutions. Gugler/Liebensteiner insist that their cost function is correctly specified, but WIK-Consult disagree, pointing out that even the first-best solution proposed by Gugler/Liebensteiner (i.e. including factor prices) crucially lacks factor prices for intermediate consumption. WIK-Consult argue that a second-best solution (i.e. leaving aside factor prices) is reasonable if we assume that there are competitive markets for intermediate consumption. Data quality issues in connection with the input factor labour are also discussed by Swiss Economics 2018b.

Gugler/Liebensteiner 2018d, Gugler/Liebensteiner 2018e and Frontier Economics 2018b point out that deflating costs without taking into consideration input prices results in overestimating productivity growth. While we do not agree with this argument, we take the concerns voiced by the respondents into account and apply a cautious approach in setting X-gen.

ii) Polynomial time trend

Oesterreichs Energie and Gugler/Liebensteiner propose modelling the time trend in the cost function through a second-degree polynomial. However, this implies that the confidence intervals for factor productivity growth depend on the time index; particularly for the more recent years, they display a funnel shape. Zero as a value is included and the estimate becomes insignificant. Gugler/Liebensteiner 2018d argue that the prediction interval widens as the period under consideration is extended further into the future, thereby reflecting increased insecurities. We cannot agree with this argument: the funnel shape of the confidence intervals that comes from including a time trend in the form of a second-degree polynomial does not reflect the insecurity of predicting future developments. Instead, it comes from correctly including a data set that begins in 2002. Also, the data do not support the hypothesis that productivity potentials should decrease over time; statistical tests of the data rather confirm a linear development.

For these reasons, we do not include a polynomial time trend.

iv) Firm-fixed effects

Frontier Economics and WIK-Consult include firm-fixed effects in their specifications. Gugler/Liebensteiner do not do so; instead, they opt for a pooled OLS approach. They argue that including firm-fixed effects would lead to negative and mostly insignificant output coefficients given that the outputs of individual electricity DSOs reflected in the cost function do not vary strongly over time. They consider this a distorted and unfair representation of the actual situation. However, Gugler/Liebensteiner 2018e also state that the statistical significance of an estimated parameter should not be used as an argument for choosing one model over another.

WIK-Consult apply statistical tests (an F-test and a Hausman test) and on their basis propose including firm-fixed effects. More precisely, they use the data collected by us, perform a dynamic cost driver analysis and apply the AIC and BIC criteria for model selection. They do not confirm suitability of a pooled OLS approach.

v) Uniform data set

As stated above, we put together a data set, double-checked it with the companies and provided it to the consultants so that they might calculate factor productivity growth. Gugler/Liebensteiner add their own data to the calculations, which is why we cannot replicate their results. Instead, we stick to the E-Control data set throughout.

In this context, Gugler/Liebensteiner 2018e criticise our standardised CAPEX approach (i.e. in the form of annuities) as inadequate. E-Control does not share this view; to the contrary, we reject the financial accounting approach to CAPEX taken by Gugler/Liebensteiner, because the useful life applied in financial accounting does not correspond to the actual useful life of the assets.

vi) Bernstein-Sappington formula

Oesterreichs Energie criticise that we do not reference the Bernstein-Sappington formula. Following WIK-Consult 2018b, we believe that Bernstein and Sappington's differential formula does not apply to the Austrian regulatory context.

Conclusions

We take into consideration the X-gen values calculated by Gugler/Liebensteiner, Frontier Economics und WIK-Consult, as well as the arguments brought with reference to future insecurities, factor prices and possible catch-up effects.

To enable this, WIK-Consult use the specification from Gugler/Liebensteiner 2018c (table 3, specification 2) with deflated OPEX, factor prices, and the RAB to account for the possibility of an OPEX-CAPEX shift. WIK-Consult exclude the non-significant quadratic time trend. The resulting specification is then applied to our 2002-2016 data set. While Gugler/Liebensteiner estimate TFP growth at -0.08%, statistically indistinguishable from zero, the above adjustments lead to a statistically significant result of 0.97% p.a. with a 95% confidence interval of 0.47-1.47% (cf. WIK-Consult, tables 4-5, specification 3b).

Overall, we reference the following studies for setting X-gen:

> Gugler/Liebensteiner 2018c, replicated by WIK-Consult 2018
  Estimated TFP growth: 0.97% p.a., 95% confidence interval: 0.47-1.47% p.a.
> WIK-Consult 2018
  Estimated TFP growth: 1.72 % p.a., 95% confidence interval: 1.10-2.35% p.a.
> Frontier Economics 2018b
  Interval of 0.3-2.6% p.a., recommendation towards the lower end

We believe that these three studies reasonably delineate the lower and upper ends of the adequate interval, i.e. 0.3-2.6%. When choosing at which level within this interval to set the general productivity growth rate, we must bear in mind that technological development introduces insecurity to productivity projections and that the question of factor prices is not straightforward (cf. the discussion about the specification of the cost function). By applying the lower 95% confidence intervals, we reflect these considerations and the interests of the regulated companies. The resulting narrowed interval is 0.47% (Gugler/Liebensteiner 2018c, replicated by WIK-Consult 2018) to 1.45% (average of the Frontier Economics 2018b interval).

The Austrian Economic Chamber appealed against the 0.815% p.a. general productivity growth rate in our official decision. This value represents the arithmetic mean of the two lower 95% confidence intervals by Gugler/Liebensteiner 2018c, replicated by WIK-Consult 2018 and WIK-Consult 2018, and of the lower quarter of the range recommended by Frontier Economics 2018b.[26]

According to the Austrian Economic Chamber, we took too cautious an approach by focussing on the lower end of the ranges. We acknowledge the logic behind their arguments and, though the appeals proceedings are still ongoing, we now envisage a general productivity growth rate of 0.95% p.a. This is a cautious approach that balances the interests of all affected parties and that is within the adequate range indicated above.

[26] The corresponding formula is:

$$X_{gen} = \frac{0.47\% + 1.10\% + (0.3\% + (2.6\% - 0.3\%) * 0.25)}{3} = 0.815\%\ p.a.$$

Given this approach and as shown by the sensitivity analysis conducted by WIK-Consult 2018 (cf. the discussion around the Malmquist index), there is no need for additional cautionary measures to account for any catch-up effects.

6. Individual efficiency targets (X-ind)

The efficiency potential for each company is derived from an efficiency benchmark. The various methods that can be used for this purpose are explained and discussed below.

In order to determine each regulated company's individual efficiency target, the calculated inefficiencies are stretched over a certain period of time. This reflects that companies can control their own efficiency and at the same time provides them with attractive incentives for productive behaviour.

Whether an efficiency floor must be set and how long the realisation period should be crucially depends on the distribution of efficiency scores. This is further discussed in chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**; the paragraphs below describe the benchmarking methodology.

The purpose of benchmarking is to assess whether the actual costs of system operation are consistent with rational management decisions. This responds to the statutory requirement to identify the costs of one or more comparable companies that are run (relatively) efficiently. The actual costs of each individual company are then benchmarked against the costs of its efficient peers.

The benchmarking analysis can be broken down into three steps:

1. Select the benchmarking method(s).
2. Select the variables on the cost side (inputs) and on the performance or structure side (outputs).
3. Perform the efficiency benchmark.

Based on the selected methods and variables, each company's efficiency and any potential for increasing efficiency are calculated. Please note that the analysis reveals only the *relative* efficiency of the companies that are compared to each other. Companies with high scores are not necessarily efficient in absolute terms, i.e. efficiency potentials could exist for them as well. In addition, the fact that this is a static analysis means that efficiency levels can change and do not necessarily converge (dynamic aspect).[27]

We are basing the benchmarking exercise for the fourth incentive regulatory period on the considerations and lessons learnt during the previous editions, i.e. in 2005 and 2013, when we conducted benchmarking exercises for the first and third regulatory periods. The most significant adjustments we introduce relate to the analysis of cost drivers, the specification of output parameters and the insights inferred from the cost driver analysis. For the outlier analysis, we mostly stick to the methodology and thresholds applied in 2013.

As a general principle, all methods and parameters that we use to set targets must correspond to the state of the art (section 59(2) Electricity Act 2010).

As previously, we benchmark only grid levels 3-7. We exclude levels 1 and 2 because only a very few companies operate these grid levels and even where they do, these operations relate to specific facilities whose effects can easily be isolated. Even so, each company's individual (weighted) efficiency score for levels 3-7 in the end applies to all grid levels it operates.

Our benchmarking sample contains 38 regulated electricity DSOs, all of whom transported more than 50 GWh through their networks in 2008. To account for heterogeneity across the companies,

[27] For a more detailed discussion of converging efficiency scores, please consult chapter 6.7.

we use appropriate definitions for the structural and performance parameters (outputs) and costs (inputs), an ex-ante cost driver analysis and a relevant model specification.

6.1. Benchmarking methodology

When benchmarking to set targets, we can choose from a range of methodologies. Generally, we differentiate between non-parametric methods such as data envelopment analysis (DEA) and parametric methods such as modified ordinary least squares (MOLS). There are also alternative stochastic methods such as stochastic frontier analysis (SFA) and hybrid models such as stochastic data envelopment analysis (SDEA) and stochastic non-parametric envelopment of data (StoNED). In a study commissioned by E-Control, Gugler et al. 2012[28] evaluated these alternative methods in terms of their theoretical foundations and suitability for practical use in the Austrian regulatory context.

In SFA, the residual (error term) is divided into two components: one representing inefficiency and another representing data noise. This distinction is made using statistical methods and requires observations for a sufficient number of companies. The German regulatory authority Bundesnetzagentur, for example, draws on a data set with well over 100 companies to calculate the efficiency of electricity and gas distribution system operators. Gugler et al. 2012 conclude that the data available in Austria are not sufficient for SFA.

With regard to hybrid models (including SDEA and StoNED), Gugler et al. 2012 find it difficult to compare the advantages and disadvantages of these methods. Unlike methods such as DEA and MOLS, which are well established and have been sufficiently evaluated, hybrid methods have not yet been adequately appraised and are hardly applied in practice.

Based on the above arguments, we see no reason for using methods other than the ones that have proven reliable in the past (DEA and MOLS). They both continue to reflect the state of the art. We consider them both to be equally suitable to our task.[29]

While a detailed discussion of the subject is available elsewhere, we make reference to the main arguments in the chapters below. We also point out where there have been advances in benchmarking in the context of incentive regulation in Austria (benchmarking of electricity and gas distribution system operators) and at the European level (TSO benchmarking).

6.1.1. Data envelopment analysis (DEA)

DEA is a non-parametric method, i.e. it constructs the efficiency frontier solely based on observed best-practice companies (instead of referencing a production context that would be described using econometric estimations). This also means that there is no need for an underlying cost function.[30] DEA is by far the most widely applied non-parametric benchmarking method. Not only is it easily understood, it also allows for a heterogeneous sample of companies to be modelled relatively easily. Another advantage is that it can be used with constant or variable returns to scale (cf. the discussion on returns to scale below).

Data quality is crucial as any deviation from the efficiency frontier is interpreted as inefficiency (i.e. we can speak of a ‘deterministic’ method).

A major disadvantage of DEA is that efficiency values are biased upwards in cases where few observations occur in conjunction with a large number of outputs (‘curse of dimensionality’). The

[28] Gugler, K., Klien, M., Schmitt S. (2012), *Wirtschaftswissenschaftliches Gutachten zu Benchmarkingmethoden für die österreichischen Energienetze* (Economics expert study of benchmarking methods for Austrian energy networks), study commissioned by E-Control.
[29] The features as well as the advantages and disadvantages of the two methods are described in the explanatory notes on the 2006 Electricity and the 2008 Gas System Charges Ordinances and in Frontier-Economics/Consentec 2004. A further discussion is available in Gugler et al. 2012.
[30] Cf. in general the explanatory notes on the Electricity System Charges Ordinance 2006, pp. 35 et seq.

more dimensions, the greater the risk of a separate dimension for each company, in which by definition no other (more efficient) company can exist; efficiency scores converge on 1.

DEA is also highly sensitive to outliers. Best-in-class companies are assigned a score of 1 (perfect efficiency) and thus represent the efficiency frontier, while the efficiency of the remaining companies is relative to that frontier. Consequently, outliers can strongly impact the efficiency scores of the 'enveloped' companies.

In view of the aspects mentioned above, we put great emphasis on verifying that input data are complete and correct (using plausibility and validity checks) and on analysing outliers. In addition, the advantages and disadvantages of the second method that we apply, MOLS, are almost exactly the opposite of those associated with DEA (cf. the next chapter).

6.1.2. Modified ordinary least squares (MOLS)

In contrast to DEA, MOLS is a parametric method and requires a cost function that specifies the relationship between inputs and outputs.[31] This functional relationship is modelled by means of an OLS estimation, which represents the basic (average) relationship between inputs and outputs. To model the efficiency frontier, the OLS line is shifted by the standard error of the regression. Under the assumption that the inefficiency term is exponentially distributed, the shift is by the root mean square error (RMSE), i.e. by the standard error of regression; assuming a half-normal distribution of the inefficiency term, the shift is by $RMSE \times \frac{\sqrt{2}}{\sqrt{\pi}}$.

The outward shift increases with the variance of the residuals and consequently with the estimator for the average inefficiency, i.e. the extent to which the companies deviate from the efficiency frontier. This ensures that most data points, but not all of them, are enveloped. It is this characteristic that renders MOLS less sensitive to outliers than DEA.

We assume a half-normal distribution for the inefficiency term, i.e. the efficiency frontier is not shifted out as far as it would be under an exponential distribution assumption. This generally results in higher efficiency scores. Employing a function that takes a log-linear form (i.e. Cobb-Douglas or translog), efficiency scores are calculated as follows:

$$Effizienzwert\_MOLS = \min\left(1\,;\,\frac{1}{e^{\left(Residuum+RMSE\times\frac{\sqrt{2}}{\sqrt{\pi}}\right)}}\right)$$ [32]

6.1.3. Returns to scale

As mentioned above, both DEA and MOLS can work with various assumptions concerning returns to scale. While parametric methods allow testing for returns to scale, an a priori decision might be preferable from the standpoint of regulatory policy. This holds all the more where regulated companies can choose their company size themselves.

At the beginning of the third regulatory period, we assumed constant returns to scale for both MOLS and DEA. We continue with this approach.

6.1.4. Form of the function and zero-output level

As for the previous regulatory period, we use a log-linear Cobb-Douglas cost function for the parametric benchmark. To address the issue of zero-output levels, we aggregate several individual

[31] Cf. in general the explanatory notes on the Electricity System Charges Ordinance 2006, pp. 38 et seq.

[32] In English:

$$EfficiencyScoreMOLS = \min\left(1\,;\,\frac{1}{e^{\left(Residual+RMS\ \times\frac{\sqrt{2}}{\sqrt{\pi}}\right)}}\right)$$

weighted outputs into a combined output parameter. For further details, please consult the description of the benchmark for the third regulatory period.

6.2. Specification of benchmarking parameters

A benchmark basically compares the ratio of outputs to inputs among companies to arrive at an efficiency score. This can be approached from either the input or the output side. The idea of the first approach is that an externally given number of outputs is to be produced at the lowest possible inputs (costs), while with the second approach we take the inputs as fixed and look for the maximum output. In energy distribution, most of the outputs relevant for system operators are not within their control: load is driven by consumption behaviour and the number of metering points depends on the customers. Thus, the input-oriented approach seems to be more appropriate.

In terms of parameters, cost is often considered the only relevant input (i.e. the efficiency score is a measure of cost efficiency). Choosing outputs is more complex and relies on a variety of procedures, e.g. expert opinions (cost-driving effects inferred intuitively), approaches based on engineering science (engineering economic analysis) and empirical analysis using statistical significance tests. These selection methods are often combined with each other.

The following chapters discuss how we choose and specify the input and output parameters for our benchmarking exercise and explain the underlying premises.

6.2.1. Selection of input parameters

The two options for our input variable are operating expenditures (OPEX) and total expenditures (OPEX+CAPEX=TOTEX). TOTEX has the advantage that the benchmarking results are not distorted by companies' decisions about the capital intensity in their production processes. Using OPEX only could create incentives for them to shift items (e.g. certain maintenance operations) from OPEX into CAPEX or even to opt for capital investment over OPEX-intensive solutions simply to improve the benchmarking result.

Grid charges should always reflect actual costs. Following this principle, the benchmarking exercise should be based on total costs, not just on operating expenditure (and maintenance costs). Efficiency should be incentivised both for investments and operations.[33] We continue to believe that this is appropriate, which is why we use total expenditure as input for our benchmarking exercise.

The benchmark generally uses the audited costs for network levels 3-7 (cf. chapter 4.1). This excludes costs payable towards upstream grid levels but includes metering costs and uniformly priced[34] system losses, as was the case for the benchmarking exercise we conducted ahead of the third regulatory period.

We then correct the audited costs for any prepayments that have been made and for any facilities under construction; this reduces heterogeneity among the companies and results in comparable sets of costs. In addition, we make corrections in individual cases for additional costs in connection with early advanced smart meter rollout, for extraordinary costs related to injection from wind power plants, and for costs for individual reasonable cases where network level 3 carries out (some) transmission functions.

We use the historical costs for the companies' fixed assets to derive normalised, standardised CAPEX, thereby enabling comparability even though the age and useful life of the assets differ (cf. chapter Fehler! Verweisquelle konnte nicht gefunden werden.). In our draft for the regulatory regime for the fourth regulatory period, we had proposed using such standardised numbers only. However, in reaction to several responses by Oesterreichs Energie, the association of Austrian

[33] Please note that section 59(2) Electricity Act 2010 expressly states that assessing individual processes is admissible.
[34] In accordance with section 59(6) Electricity Act 2010, the rate payable for the energy needed to cover system losses constitutes non-controllable costs.

power plants (Vereinigung Österreichischer Elektrizitätswerke) and affected companies, we are now using financial accounting numbers as well. We agree with the argument that relying exclusively on standardised CAPEX might encourage companies to upgrade their ageing infrastructure but might also induce them to exchange well-functioning assets, i.e. it might lead to premature replacements. This is economically inefficient. Also, the method cannot adequately depict the direct connection between older network infrastructure with lower capital cost and higher maintenance requirements on the one hand, and between newer systems with higher capital cost and lower operational expenditures on the other. For these reasons, we use both standardised and financial accounting numbers for our efficiency benchmark. A company's final efficiency score is the better of the two scores calculated with the two sets of cost data.

6.2.1.1. Standardising CAPEX

The concept of using annuities to standardise capital cost for benchmarking was introduced for the third regulatory period. We maintain and update this approach for the new period.

The historical costs incurred in acquiring or producing the items in the individual asset categories are indexed by first year of operation, enabling us to calculate their current replacement values. We combine this data with standardised useful life periods and a real interest rate to derive annuities (i.e. constant payments over the entire useful life). This involves the following steps:

> Recording the investment time series for all asset categories (using the asset category data for the electricity sector);
> Determining a suitable index for the average changes in fixed asset prices;
> Determining the term of the annuity ('depreciation period');
> Determining the interest rate for the annuity ('real WACC').

By applying a price index to the historical costs, we can derive indexed historical costs or the assets' replacement value. No specific inflation rates are available for the various asset categories during the required period (50 years in many cases);[35] as during the previous regulatory period, all asset categories are therefore indexed using the consumer price index (*Verbraucherpreisindex*, VPI). After calculating the indexed costs for each asset category, the annuities (i.e. the standardised CAPEX) are determined using a uniform real interest rate[36] (=(1+WACC)/(1+VPI)-1) and a uniform useful life for each asset category. We use the classic form of the annuity formula :

$$Annuität_i = \sum AHK_i^{ind} \times \frac{(1+rZ)^{AD,i} \times rZ}{(1+rZ)^{AD,i} - 1}$$ [37]

where

$\sum AHK_i^{ind}$ is the sum of the indexed historical costs (replacement value) for asset category *i*

rZ is the real interest rate, and

AD,i is the useful life of asset category *i*.

The standardised (but not yet normalised) CAPEX are the total annuities of all relevant asset categories.[38]

[35] In Germany, a specific inflation rate was used for each individual asset. Neither industry representatives nor the industry consultant (Consentec) have raised objections against using the consumer price index or proposed better suited methods.
[36] Indexing the investment time series requires a real interest rate. The VPI is based on the same period as the one used in determining the risk-free interest rate for the WACC (five years).
[37] In English:
$$Annuity_i = \sum HistoricalCosts_i^{indexed} \times \frac{(1+RealInterestRa\quad)^{UsefulLife,i} \times RealInterestRate}{(1+RealInterestRat\quad)^{UsefulLife,i} - 1}$$

[38] This does not include assets at grid levels 1 or 2, prepayments made and facilities under construction at grid levels 3-7, goodwill or any securities, stocks and bonds.

The appropriate standardised useful life for each asset category relies on actual company data. We use the 75% quantiles of the data submitted by the regulated companies for each asset category since we started data collection and we consider the companies' reactions to our first proposal. In the end, we apply the following standardised useful life periods:

Asset category	Standardised useful life (years)	Asset category	Standardised useful life (years)
A.2 Software	5	B14a Meters and metering equipment	15
A.3 Easements and other rights	25	B14b Meters (remote reading)	15
A.4 Prepayments f. installation costs	20	B15 Power generators for outages	15
A.5 Other immaterial goods	5	B16 Business premises	33
B5 Overhead lines (36> to 110 kV)	33	B17 Operational buildings	33
B6 Cables (36> to 110 kV)	33	B18 Land	
B7 Transformers (HV-MV)	20	B19 Motor vehicles	8
B8 Overhead lines (10+20k)	25	B20 Machinery	10
B9 Cables (10+20k)	25	B21 IT equipment	5
B10 Transformers (MV-MV)	25	B.22 Telecoms equipment	20
B11 Transformer station	20	B.23 Low-value assets	1
B12 Overhead line (<1kV)	20	B.24 Other	5
B13 Cables (<1kV)	20	B.26 Other non-durables	1

Figure 1: Standardised useful life periods used to calculate annuities

These periods are slightly longer than the ones we used for the third regulatory period.

We keep the idea of normalising the annuities so as to preserve the original CAPEX/OPEX ratio for the industry (which was derived from cost accounting data). To do this, we determine the ratio of standardised CAPEX (annuities) to financial accounting CAPEX for each company (individual normalisation factor) and then derive the median ratio of standardised to financial accounting CAPEX (general normalisation factor). We divide all annuities by this general normalisation factor to render normalised standardised CAPEX. In formal terms:

$$Normierte\ standardisierte\ CAPEX\ = \frac{Annuität}{generellen\ Normierungsfaktor}$$ [39]

Our normalisation factor for the fourth regulatory period, i.e. the median of the companies' individual normalisation factors, is 2.94.

The normalisation factor for an individual company j is defined as

$$Individueller\ Normierungsfaktor_j\ = \frac{Annuität_j}{CAPEX\ kalkulatorisch_j}$$ [40]

6.2.1.2. Correcting TOTEX

To reduce heterogeneity, we correct the standardised CAPEX, the financial accounting CAPEX and the operational expenses for several firm-specific effects. These corrections are in line with the criteria for the third regulatory period (cf. chapter 6.2.1.1 in the document about that period). We correct for

- any transmission functions at grid level 3;
- smart meter investments;
- investments related to wind power plants;
- prepayments for installation costs arising for companies in extraordinary situations.

[39] In English:

$$NormalisedStandardisedCAPEX\ = \frac{Annuity}{GeneralNormalisationFactor}$$

[40] In English:

$$IndividualNormalisationFactor_j\ = \frac{Annuity_j}{FinancialAccountingCAPEX_j}$$

In addition, we correct all companies' operational expenditures to fit them for benchmarking. Unlike for the previous regulatory period, this time we account for disbursement periods and annual sums to standardise provisions for personnel costs. Please note that this is for benchmarking purposes only; it does not affect the inclusion of provisions for personnel costs in the allowed costs. The intention with standardising is to minimise the absolute differences between the standardised amount and the cash flow during the entire disbursement period. This way, the extraordinary expenses of companies arising from re-evaluation of past personnel costs are stretched over several decades.

Following the above considerations, here are the input specifications that are relevant for the efficiency benchmark:

Annuity / normalisation factor = standardised CAPEX	Financial accounting CAPEX - corrections = financial accounting CAPEX
+ BM OPEX (grid levels 3-7)	+ BM OPEX (grid levels 3-7)
+ costs to cover grid losses	+ costs to cover grid losses
= BM TOTEX, standardised	= BM TOTEX, financial accounting

Figure 2: Benchmarking input costs

We calculate the costs to cover grid losses in the same way as previously: we take the energy amounts that were necessary to cover grid losses in 2016 and multiply them by the price paid in the joint procurement procedure, i.e. 32.4 EUR/MWh.

Using two benchmarking methods (MOLS and DEA) and two sets of cost data (standardised TOTEX and financial accounting TOTEX), we calculate four efficiency scores for each company.

6.2.2. Outputs

An efficiency analysis's outputs must reflect external, structural and environmental conditions beyond the companies' control. In order to guarantee a high level of discriminatory capacity, as few parameters as is possible should be used. The parameters must also be cost drivers and it should be possible to derive them from available data.

The below analysis builds on the experience gained in previous benchmarking exercises.

Analysis of cost drivers

As in previous benchmarking exercises, transformed area-weighted connection density (trfNAD) is a relevant cost driver, both if disaggregated (i.e. differentiating between high, medium and low voltage) and aggregated (weighted). To get recent information, we commissioned Consultant RSA – iSPACE with analysing and updating the areas covered by using suitable underlying data. The premises of the regulatory regime for the third period were left unchanged, but the update relies on a more detailed grid analysis (spacing around buildings) as well as updated and more detailed street graphs. A more precise method now applies for areas with a >25° incline.[41] Areas of ≥ 1,800 metres above sea level are excluded from the analysis unless there are buildings higher up. In identifying settlement clusters and building numbers, the analysis previously relied on a grid with a resolution of 100 metres; now it can identify each individual building. Also, the data used no longer come from the commercial Teleatlas 2012 data set; instead, the street graph is approximated using the federal provinces' infrastructure data (GIP). Land-use data are taken from

[41] We speak of "areas with a >25° incline" in all cases where both models 1 and 2 have a value of >25°, where:
Model 1: area of 10 x 10 metres with an incline derived from the 10 x 10 metre elevation model
Model 2: area of 10 x 10 metres with a calculated average incline over an area with a radius of 100 metres
This way we can reap the benefits of the more exact 10 x 10 metre resolution while preventing small areas (only a few 10-metre squares) with different inclinations from being excluded immediately.

the Corine 2012 data set (previously: Corine 2006), topography is derived from the ogd-dgm data that rely on airborne laserscan with a resolution of 10 metres (previously: srtm data based on 90 metre resolution radar). This approach to calculating the areas covered was discussed and agreed with industry consultant Consentec.[42]

We also identified peak load to be a relevant cost driver. Industry representatives promoted the idea of reflecting demographic trends by using the highest peak load registered during a reference period that spans several years. We discussed this and agree that a rolling period would best reflect demographic developments and enable system operators to react to them. As previously, we cap the variable for peak load (for grid levels 4-7 and 6-7) at the value of the fifth highest quarter-hourly load measured during each business year, but we extend the reference period from two to five years (2012-2016).

Another cost driver is the number of (withdrawing and injecting) metering points.[43] There are different types of metering points, including unidirectional meters, points with interruptible rate meters, dual rate meters and bidirectional meters. Our data distinguish between these types of metering points and between grid levels 3-7 and 6-7.

In their reactions to the draft regulatory regime, a number of companies discussed issues related to metering points with interruptible rate meters, dual rate meters and bidirectional meters. One company suggested eliminating metering points as an output variable, regardless of whether the numbers are significant or not. They proposed using the outputs from the third period instead. We do not follow this argument and point to the presentations and discussions held at several expert meetings (cf. the slides and minutes of these meetings), during which both E-Control and the industry consultant Consentec underlined the relevance of metering points as a cost driver.

Another company considered that it was treated unfairly: it has a high share of interruptible metering points with ripple control. This reduces the peak load, which in turn puts them at a disadvantage compared to other companies. Only by correcting for the costs of the ripple control system and by adjusting their peak load upwards could the numbers be made comparable. We do not agree with this argument and cannot identify any unfair treatment: a properly run ripple control system indeed reduces peak load, thus also bringing down the need for costly network expansion. Therefore, the company's as-is costs adequately correspond to the output (and deviations indicate efficiency potentials).

A third company pointed to its high share of dual rate meters; they believe these should be counted twice because the same functionality would otherwise have to be provided by two devices (a normal withdrawing metering point and an interruptible metering point). Given that the draft regulatory regime for the fourth period counts dual rate meters only once, the company saw itself at a disadvantage.

After a detailed consideration of this issue, we now differentiate between dual rate meters, bidirectional meters, interruptible meters, and normal, unidirectional meters. Even efficiently deployed interruptible meters cause additional metering and operational costs. However, apart from the devices themselves and any ripple control systems necessary, they do not add to a company's capital cost as they enable load shifting, thereby bringing down peak load and reducing the need for network expansion. We would have preferred using activity-based costing to investigate this matter further, but the regulated companies rejected the idea of clearly delimiting the processes and reporting the relating numbers. Therefore, we use the following proxy information: the collected metering charges; the additional OPEX (the ratio between grid level 6-7 OPEX and grid level 3-7 TOTEX); and the depreciation for a company's ripple control system. Dual

[42] For the equations used to calculate the model network length, please refer to the document that explains the regulatory regime for the third regulatory period or to the explanatory notes on the Electricity System Charges Ordinance 2006.

[43] Please note that system operators do take meter readings at transformer substations but that these are for operational purposes only. They are not relevant for the grid charges, which is why we do not count them towards the number of metering points as a benchmarking output.

rate meters eliminate the need for a second metering device, i.e. the ratio between the collected metering charges and the TOTEX should not be part of the equation. The same holds for bidirectional meters; in addition, the element that accounts for any ripple control system must be eliminated for this type of metering point.

In line with the above considerations, the different types of metering points are weighted as follows:

$$Unterbrechbar = \frac{OPEX\ NE\ 6\ u.\ 7 - Messentgelte\ NE\ 6\ u.\ 7}{kTOTEX\ exkl.\ NV\ - Messentgelte} + \frac{Messentgelte}{kTOTEX\ exkl.\ NV} + \frac{Abschr.\ Rundsteueranlage}{kTOTEX\ exkl.\ NV} = \mathbf{37,50}\% \quad [44]$$

$$Doppeltarifzähler = \frac{OPEX\ NE\ 6\ u.\ 7 - Messentgelte\ NE\ 6\ u.\ 7}{kTOTEX\ exkl.\ NV\ - Messentgelte} + \frac{Abschr.\ Rundsteueranlage}{kTOTEX\ exkl.\ NV} + 1 = \mathbf{126,75}\% \quad [45]$$

$$Beide\ Richtungen = \frac{OPEX\ NE\ 6\ u.\ 7 - Messentgelte\ NE\ 6\ u.\ 7}{kTOTEX\ exkl.\ NV\ - Messentgelte} + 1 = \mathbf{126,50}\% \quad [46]$$

To also incentivise operators to increase their systems' utilisation, we proposed a so-called smart grid variable that weighs the metering points by full-load hours (electricity supplied at grid levels 4 to 7 / peak load at grid levels 4 to 7 x number of metering points). In addition, we wanted to capture the effect of intermittent injection, considering that total maximum injection capacity and maximum capacity for wind and PV injection could be cost drivers. However, industry consultant Consentec rejected these proposals, quoting engineering considerations.

Model specification

We provided the industry consultant with our data set. Both the consultant and E-Control find that the specification used for the third regulatory period is no longer adequate for the new efficiency benchmark because by including peak load at both grid levels 4-7 and 6-7, the necessary statistical significance levels for the cost driver analysis are no longer reached. We discussed three specification options with Oesterreichs Energie, selected company representatives, Consentec and the statutory parties. All three options include TOTEX and the area-weighted connection density (trfNAD_gesamt in the aggregate form and trfNAD_HSP, MSP, NSP for different voltage levels in the disaggregate form).

[44] In English:

$$InterruptibleMeteringPoints = \frac{OPEXNetworkLevels6And7 - MeteringChargesNetworkLevels6And7}{FinancialAccountingTOTEXExcludingCostForGridLosses - MeteringCharges} + \frac{MeteringCharge}{FinancialAccountingTOTEXExcludingCostForGridLosses} + \frac{DepreciationRippleControlSystem}{FinancialAccountingTOTEXExcludingCostForGridLosses} = \mathbf{37.50}\%$$

[45] In English:

$$DualRateMeteringPoints = \frac{OPEXNetworkLevels6And7 - MeteringChargesNetworkLevels6And7}{FinancialAccountingTOTEXExcludingCostForGridLosses - MeteringCharg} + \frac{DepreciationRippleControlSystem}{FinancialAccountingTOTEXExcludingCostForGridLosses} + 1 = \mathbf{126.75}\%$$

[46] In English:

$$BidirectionalMeteringPoints = \frac{OPEXNetworkLevels6And7 - MeteringChargesNetworkLevels6And7}{FinancialAccountingTOTEXExcludingCostForGridLosses - MeteringCharge} + 1 = \mathbf{126.50}\%$$

Modellspezifikation	MOLS	DEA	DEA
V0	sTOTEX trfNAD_gesamt NHL_47 ZP_gesamt	sTOTEX trfNAD_gesamt NHL_47 NHL_67 ZP_gesamt	sTOTEX trfNAD_HSP, MSP, NSP NHL_47 NHL_67 ZP_gesamt
V1	sTOTEX trfNAD_gesamt NHL_47 ZP_gesamt	sTOTEX trfNAD_gesamt NHL_47 ~~NHL_67~~ ZP_gesamt	sTOTEX trfNAD_HSP, MSP, NSP NHL_47 ~~NHL_67~~ ZP_gesamt
V2	sTOTEX trfNAD_gesamt Vollast_h_ZP NHL_67 ESP_MW	sTOTEX trfNAD_gesamt Vollast_h_ZP NHL_67 ESP_MW	sTOTEX trfNAD_HSP, MSP, NSP Vollast_h_ZP NHL_67 ESP_MW

The industry prefers option V0. Apart from trfNAD, it includes not only the number of metering points (ZP_gesamt) but also peak load at grid levels 4-7 (NHL_47) and 6-7 (NHL_67) in both DEA models, while option V1 uses the former but not the latter. Consentec argue in favour of including both parameters because DEA, as a deterministic efficiency benchmarking method, is not affected by collinearity (MOLS, a parametric methodology, is.), and because it makes sense from an engineering point of view.

Option V1 views peak load at grid levels 6-7 and the number of metering points as substitutes for one another and in the end, focusses on the parameters that emerge as significant from the cost driver analysis (i.e. connection density, peak load at grid levels 4-7 and number of metering points).

Option V2 uses the smart grid variable proposed by E-Control (the metering points weighted by full-load hours, Vollast_h_ZP) and the injection capacity (ESP_MW).[47]

Generally, all three options can be used to measure system operators' efficiency. The industry criticised several characteristics of option V2: they said it created ex-post incentives that could not be anticipated by the system operators, which made it impossible to respond to the incentive mechanism; and they argued that the grid charges in their current setup would not even allow them to influence the smart grid variable. They offered to actively contribute to future debates about how to incentivise better grid utilisation but underlined that this would have to be part of a general overhaul of the grid charges.

Option V0 carries more output variables than option V1, which is why DEA automatically delivers the same result for the two options or better scores for option V0. Given that the difference between the two options is marginal, we do not consider further analysis to be worthwhile but instead follow the industry's suggestion to use option V0. This particularly holds because we combine the weighted scores from DEA and MOLS to calculate one result for each cost data set and then proceed with the better of these results. If we were to use only one method (the one with the better results), we would need to conduct a more in-depth analysis of the redundancy of the two DEA specifications, of lacking weight restrictions and of potential over-specification of DEA due to the engineering considerations mentioned above.

6.3. MOLS specification

Based on the above, the model specification for the MOLS benchmarking exercise is as follows:

[47] We tested the parameters' significance for all input specifications both with and without robust standard errors. The injection capacity proposed for option V2 was slightly significant at the 10% level.

- Functional form: log-linear
- Specification of returns to scale: constant returns to scale
- Input: standardised TOTEX and financial accounting TOTEX
- Outputs:
    - Transformed area-weighted connection densities (model network lengths)[48]
    - Peak load at levels 4-7
    - Weighted number of metering points at levels 6-7
- Inefficiency distribution assumption: half-normal

The MOLS analysis is performed with constant returns to scale and the error term transformation (calculation of efficiency scores) uses the formula described in chapter 6.1.2 (MOLS).

6.4. DEA specification

As for the third regulatory period, we use DEA with two different specifications to calculate two different scores. One of them uses the aggregated area-weighted connection density, the other uses disaggregated connection density numbers. Without creating precedence, we again do not apply weight restrictions. The DEA specification under option V0 is as follows:

DEA 4

- Input-oriented analysis
- Specification of returns to scale: constant returns to scale
- Input: standardised TOTEX and financial accounting TOTEX
- Outputs:
    - Transformed area-weighted connection density[49] of low, medium and high voltage (weighted model network lengths of low voltage, medium voltage and high voltage), $trfNAD_{HMNSP}$
    - Peak load at levels 4-7
    - Peak load at levels 6-7
    - Weighted number of metering points at levels 6-7

DEA 6

- Input-oriented analysis
- Specification of returns to scale: constant returns to scale
- Input: standardised TOTEX and financial accounting TOTEX
- Outputs:
    - Transformed connection density of low voltage (low voltage model network length), $trfNAD_{NSP}$
    - Transformed connection density of medium voltage (medium voltage model network length), $trfNAD_{MSP}$
    - Transformed connection density of high voltage (high voltage model network length), $trfNAD_{HSP}$
    - Peak load at levels 4-7
    - Peak load at levels 6-7
    - Weighted number of metering points at levels 6-7

[48] We keep the same weightings for the disaggregated area-weighted connection densities as for the third regulatory period.
[49] We keep the same weightings as for the third regulatory period.

6.5. Analyses of outliers

The general aim of analyses of outliers is to exclude individual system operators that could strongly sway most other system operators' scores. Outlier classification works differently for DEA and for MOLS.

In parametric methods (MOLS), a company is considered an outlier if it moves the calculated regression line to a considerable extent in either direction. Please note that in this type of regression analysis, even a distribution system operator with a below-average efficiency score could constitute an 'influential data point' and draw the estimated regression line towards itself. Therefore, statistical tests aim at generally identifying 'influential data points'. Suitable tests include DFBETAS, leverage plots, studentised residuals, DFFITS, dropped residuals and covariance ratios, but also Cook's distance; the latter is relevant for us in practice, and it is explicitly mentioned in Annex 3 of the German Incentive Regulation Ordinance as one of the methods for identifying outliers. Cook's distance measures the effect of deleting individual observations from the regression analysis. Data points with high absolute residuals and/or unusually high or low values in independent variables can distort the result of the regression; they can be identified using Cook's distance. If an observation's Cook's distance exceeds a previously defined threshold, that company is treated as an outlier and its data are excluded from further analysis. Our threshold is (4/n-k-1), where n is the number of observations and k the number of parameters.

Like for the third regulatory period, we use Cook's Distance for the outlier analysis in MOLS.

As mentioned before, MOLS enables us to identify 'positive' and 'negative' outliers. All 'positive' outliers are assigned an efficiency score of 100% (i.e. the highest score from the sample, without outliers); the 'negative' ones get the lowest efficiency score found in the sample (after eliminating the outliers). We believe this to be a fair approach; applying the lowest efficiency score from the entire sample (i.e. including the other outliers) would expose the results to the influence of the other outliers; using a score above the lowest one identified (e.g. the 80% efficiency floor) would unduly overestimate the outlier's efficiency.

In DEA, we refer to the concept of 'super-efficiencies' for identifying outliers. It enables us to quantify the influence of extremely high efficiency scores (in this case, there is no restriction to 100%). By looking at the distribution of 'super-efficiencies', we can draw conclusions regarding any outliers which could draw the efficiency frontier excessively far away from the remaining companies. Annex 3 of the German Incentive Regulation Ordinance stipulates that companies whose super-efficiency score exceeds the upper quartile value by more than 1.5 times the interquartile range (i.e. the range between the 75 and the 25% quantiles) are classified as outliers. We used the same approach during the third regulatory period and maintain it for the fourth period.

As a result, any outliers in DEA are assigned an efficiency score of 100%.

We conduct outlier analysis along the above lines for both MOLS and DEA and then eliminate the outlier data from our sample. This way, outliers do not set the efficiency frontier and there are no detrimental effects for the other companies in the same benchmarking sample. Our outlier analyses yield the following results:

Analyses of outliers			
Benchmarking methodology	MOLS	DEA 4	DEA 6
Statistical method applied	Cook's distance	Distribution of super-efficiencies	Distribution of super-efficiencies
Critical threshold for standardised costs	0.118 = 4/(38-3-1)	121.93% = Q(75%)+1.5*(Q(75%)-Q(25%))	127.66% = Q(75%)+1.5*(Q(75%)-Q(25%))
Critical threshold value for financial accounting costs	0.118 = 4/(38-3-1)	105.73% = Q(75%)+1.5*(Q(75%)-Q(25%))	126.70% = Q(75%)+1.5*(Q(75%)-Q(25%))
Number of outliers in	4 (2 of which positive)	3	4

standardised cost data			
Number of outliers in financial accounting cost data	1 (1 of which positive)	4	2

Figure 3: Analysis of outliers for different benchmarking methodologies and input specifications

6.6. Individual (weighted) efficiency score – X-ind

For each of the two input data sets, the results of the MOLS and DEA calculations are weighted at 50% each (i.e. MOLS: 50%; DEA 4: 25%; DEA 6: 25%) and combined to form each company's individual efficiency score for the fourth regulatory period. This approach replaces the weighting applied for the third period. It takes into account that both methods exhibit advantages and disadvantages (cf. chapter 6.1), i.e. given that neither method is better than the other, they are weighted equally (instead of allowing more weight for the two DEAs as opposed to the single MOLS).

In their reaction to the draft regulatory regime, the Federal Chamber of Labour agreed that this is a fair approach. Several other respondents (many companies and Oesterreichs Energie) argued that the highest of all efficiency results should be used. We firmly reject this idea. It would leave aside the complementary nature of the methods' pros and cons, and it would require another round of scrutiny as to the DEAs' over-specification (inclusion of additional 'engineering' output parameters regardless of whether they are significant or not), the unique characteristics due to missing weight restrictions, and the DEA with separate model network lengths (i.e. separately for high, medium and low voltage instead of for the overall weighted length only).

We would also like to point out that, though we continue with the practice of proceeding with the cost data set that delivers the better results (i.e. selecting the higher of the two efficiency results derived from a standardised and a financial accounting approach for each operator), this does not constitute a precedent for future regulatory periods. We reserve the right to look further into standardising OPEX; this might, but does not necessarily have to, lead us to using the efficiency scores resulting from both data sets (after weighting the DEA and MOLS scores) instead of proceeding with the better of the two scores. It might just as well, however, lead to application of the standardised data set only.

The models described above result in the following distribution of efficiency scores:

Model	MOLS	DEA 4	DEA 6
Specification	log-linear CRS	CRS	CRS
Input	standardised TOTEX	standardised TOTEX	standardised TOTEX
Outputs	option V0	option V0	option V0
Average efficiency score	89.4%	89.9%	92.0%
Lowest efficiency score	74.6%	71.5%	71.6%
Number of companies with a score of 100% (incl. outliers)	11	9	13

Figure 4: Distribution of efficiencies using standardised TOTEX

Model	MOLS	DEA 4	DEA 6
Specification	log-linear CRS	CRS	CRS
Input	financial acc. TOTEX	financial acc. TOTEX	financial acc. TOTEX
Outputs	option V0	option V0	option V0
Average efficiency score	90.4%	93.9%	94.1%
Lowest efficiency score	74.1%	73.1%	72.8%
Number of companies with a score of 100% (incl. outliers)	8	13	16

Figure 5: Distribution of efficiencies using financial accounting TOTEX

Weighting the results as described above and using the cost data set that delivers the better results, the following distribution of efficiency scores emerges:

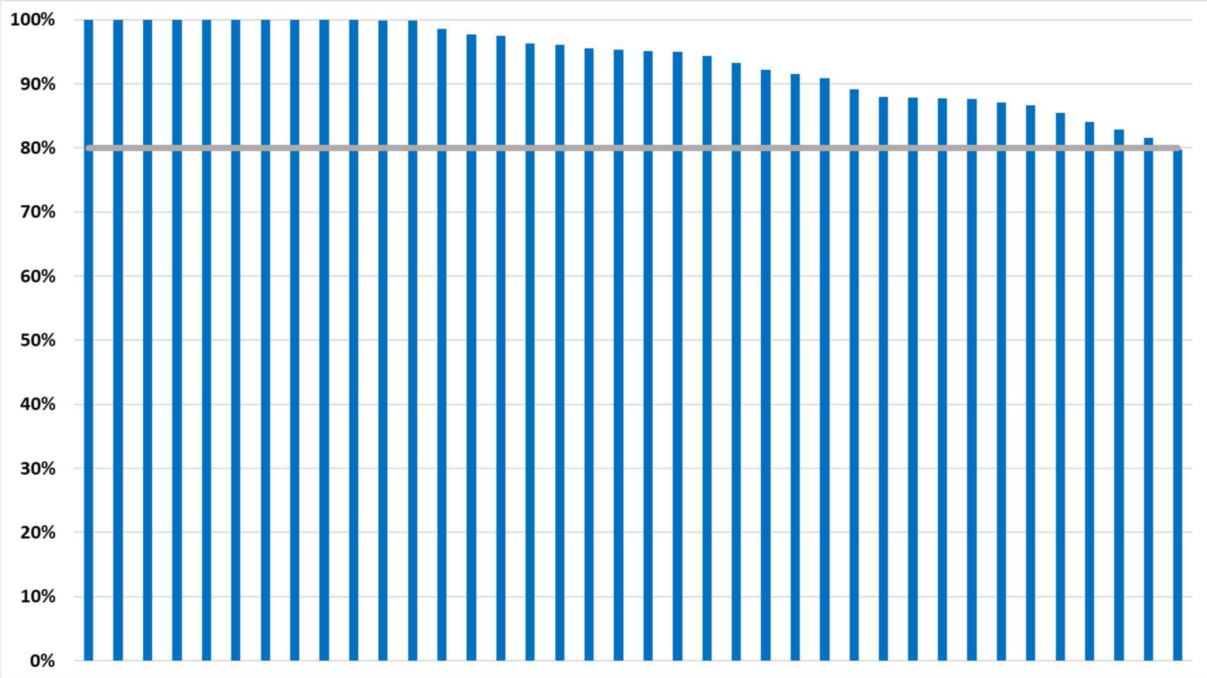

Figure 6: Distribution of weighted efficiency scores, using the better results among the two cost data sets

We use the efficiency scores from the benchmarking exercise to set targets (cf. chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**) for controllable OPEX (cf. chapter 4.2) and we use them to determine each company's individual WACC (cf. chapters 4.3.1 and 4.3.2).

6.7. Convergence of efficiency scores

In their responses to the draft regulatory regime for the fourth period, several system operators, Oesterreichs Energie and the association of Austrian power plants argued that the benchmarking results were inacceptable since they did not show converging efficiency scores, i.e. they did not detect an improvement of the average efficiency of Austrian system operators. We do not agree with this concern; instead, statistics show that efficiency scores have significantly converged. The figure below uses box plots to represent the distribution of efficiencies calculated for the third and fourth regulatory periods. To enable undistorted comparison, we apply the regime described above to all results, i.e. we weigh them accordingly (MOLS: 50%; DEA 3/4: 25%; DEA 5/6: 25%), we exclude efficiency floors and we use the better of the results delivered by the different cost data sets.

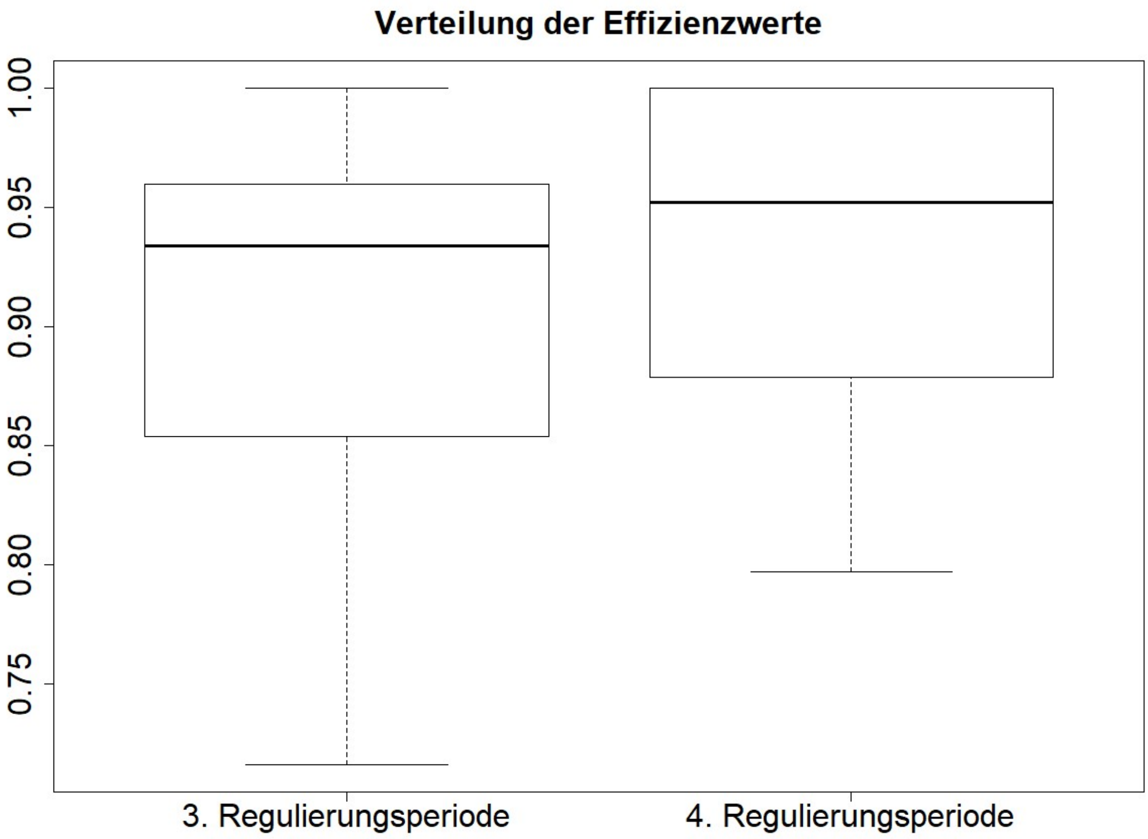

Figure 7: Distribution of efficiency scores

Many companies' efficiency scores, if weighted according to the principles for the fourth period, have improved. The figure below shows them above the red line. However, companies that have failed to realise sufficient cost reductions now have lower scores than previously; this is the nature of relative efficiency benchmarking.

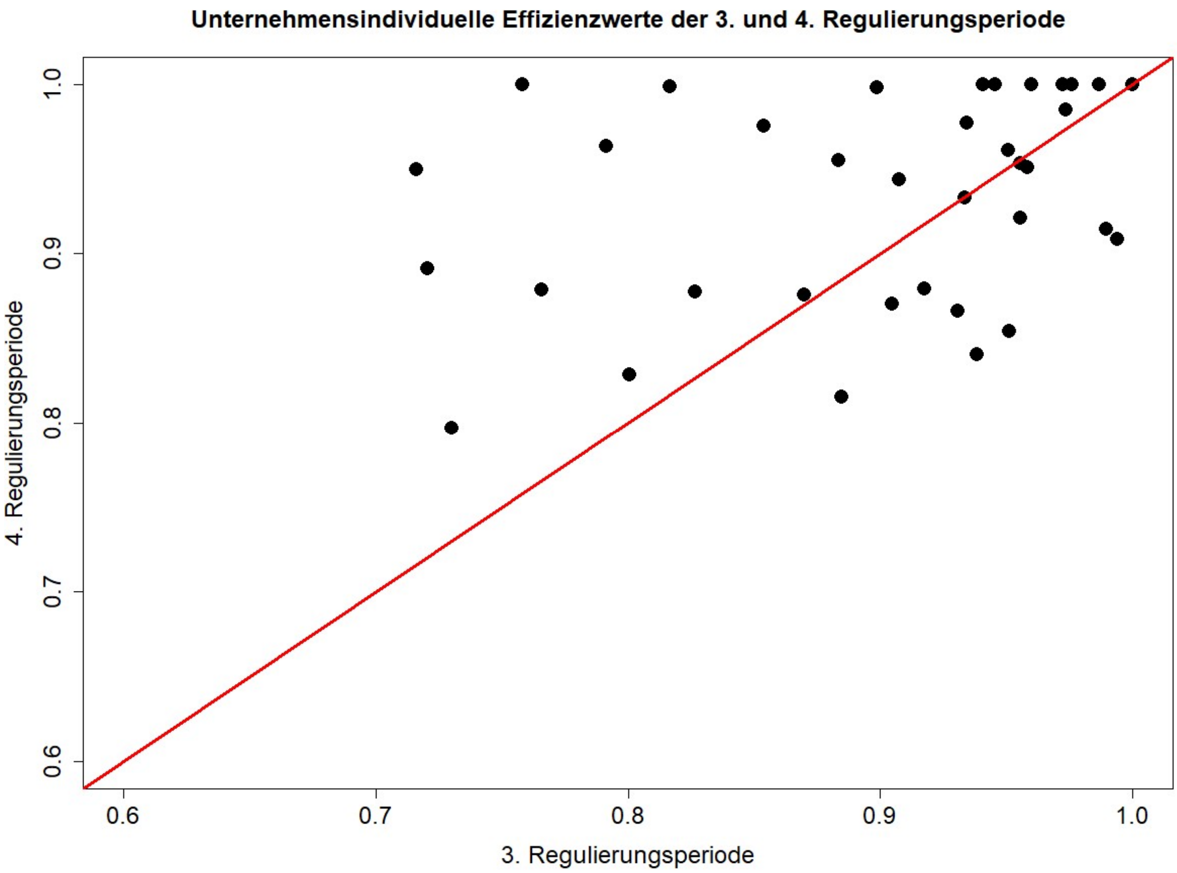

Figure 8: Individual company scores for the third and fourth regulatory periods

The above representation can be translated into numbers as follows:

	3rd regulatory period	4th regulatory period
Average	90.2%	93.6%
Median	93.4%	95.2%
Gini coefficient	0.051	0.037

First, the efficiency level has risen in general, i.e. both the median and average scores are now higher than for the third regulatory period. Second, a Mann-Whitney U test shows that the location shift of the efficiency distributions is significantly positive.

```
Wilcoxon rank sum test with continuity correction

data:  Data_4RP and Data_3RP
W = 893, p-value = 0.03789
alternative hypothesis: true location shift is greater than 0
```

Third, both the interquartile range and the lowest efficiency score have shifted upwards, which implies that efficiency scores are converging. The falling Gini coefficient confirms this observation.

Fourth, we can test for convergence with a simple linear OLS regression with the following formula:

$$\log\left(\frac{Effizienzwert_{4.Periode}}{Effizienzwert_{3.Periode}}\right) = \beta_0 + \beta_1 * \log(Effizienzwert_{3.Periode}) + \varepsilon$$ [50]

where ε is the error term. We apply OLS to the available data to estimate the parameters β0 and β1. If β1 takes a significantly negative value, this indicates that efficiency improvements in the sample are larger the lower the initial score was. This would serve as evidence for (unconditional) beta-convergence. The results are as follows:[51]

```
===============================================
                        Dependent variable:
                    ---------------------------
                      log(Data_4RP/Data_3RP)
-----------------------------------------------
log(Data_3RP)                -0.755***
                              (0.107)

Constant                     -0.042**
                              (0.016)

-----------------------------------------------
Observations                    38
R2                             0.579
Adjusted R2                    0.567
Residual Std. Error       0.065 (df = 36)
F Statistic           49.546*** (df = 1; 36)
===============================================
Note:               *p<0.1; **p<0.05; ***p<0.01
```

Scores are converging.

In 2019, the Austrian electricity DSOs embark on their fourth regulatory period. The regulatory regime should naturally evolve along with them. We believe that the incentives for productive and allocative efficiency built into the regime are important contributions to the Austrian government's climate and energy strategy as they promote careful use of scarce resources.

As the average and median efficiency scores rise, it is time for the regulatory regime to develop further; the following chapter outlines these developments.

7. Targets

A company's overall efficiency target[52] is composed of the general productivity growth rate (X-gen) and the individual efficiency target (X-ind). As in previous regulatory periods, this efficiency target is directly derived from each company's efficiency score and a certain realisation period. In accordance with section 59(3) of the Austrian Electricity Act 2010, we may divide the time given to attain the targets set (realisation period)[53] into several regulatory periods of one or more years. It is crucial to base this decision (which in turn determines the companies' annual efficiency targets) on the benchmark conducted and on the general goals of incentive regulation (productive efficiency versus allocative inefficiency). For the fourth regulatory period, we can rely on a new benchmarking

[50] In English:
$$\log\left(\frac{EfficiencyScore_{4thPeriod}}{EfficiencyScore_{3rdPeriod}}\right) = \beta_0 + \beta_1 * \log(EfficiencyScore_{3rdPeriod}) + \varepsilon$$

[51] The regression results were calculated using the package *stargazer: Well-Formatted Regression and Summary Statistics Tables* in *R* (Hlavac, 2018); details: https://CRAN.R-project.org/package=stargazer.

[52] Previously the "cost adjustment factor".

[53] Previously the "target attainment period".

exercise to determine the individual efficiency targets. Also, in order to ensure system stability, we set an efficiency floor and choose an appropriate period for realising efficiency potentials.

Regardless of how long a realisation period we set, a new benchmarking exercise must again be conducted ahead of the next regulatory period. It will enable us to update each company's efficiency target. The realisation period, the efficiency floor and the duration of a regulatory period – all of these are elements that must to be defined for each regulatory period anew.

Following the above considerations, we set an efficiency floor of 80% for the fourth regulatory period. As a realisation period, we proposed one regulatory period (i.e. five years) in the document describing the draft regulatory regime. This is in line with European practices and it provides a stronger incentive than the previous arrangement with its much longer realisation period of two regulatory periods (i.e. ten years). Numerous regulated companies and the industry associations (Oesterreichs Energie and the association of Austrian power plants) protested against this shorter timeline and insisted that the previous realisation period should be maintained. They argued that this was necessary because the efficiency scores did not converge, and they pointed towards the regulatory regime in Germany: it uses the better result from among the methods (SFA and DEA) and the cost data sets (standardised and non-standardised costs), and thus produces much higher efficiency scores.

We cannot follow the industry's arguments on this point and maintain that a shorter realisation period is sensible. As for the convergence of efficiency scores, please refer to chapter 6.7, which clearly demonstrates that Oesterreichs Energie's assumption of lacking convergence does not in fact apply; rather, statistics prove the opposite. We would also like to point out that the 'average German efficiency score' quoted by Oesterreichs Energie is misleading. Actually, they refer to an average that is weighted with the system operators' TOTEX instead of the arithmetic mean of the efficiency scores. The Austrian Economic Chamber agree with our argument on shortening the realisation period as system operators have already had three full regulatory periods to realise efficiency potentials.

Accounting for the reactions received, we modify our initial proposal and set the realisation period to one-and-a-half regulatory periods (i.e. 7.5 years). This is meant as a transitory arrangement towards full alignment of realisation and regulatory periods in future; only such alignment will enable the incentive mechanisms to unfold their full effect, in particular when efficiency scores converge.

At this point, we would like to underline that these periods are not set in stone: the duration of a regulatory period itself might be shortened, and the realisation period does not necessarily have to cover a full regulatory period. Also, the Austrian electricity DSOs embark on their fourth regulatory period in 2019. It is only logical that the regulatory regime should evolve along with them. We believe that the incentives for productive and allocative efficiency built into the regime are important contributions to the Austrian government's climate and energy strategy as they promote careful use of scarce resources.

Looking towards other European countries, we find several examples of five-year realisation periods. In Germany, the regulatory and realisation periods have been aligned since the second regulatory period; both are five years long. When the German regime was assessed, one of the options even foresaw a two-year realisation period (this was the option "TOTEX + bonus", cf. BNetzA 2015[54]).

Contrary to what the association of Austrian power plants suspect, our shortening of the realisation period is not meant to be detrimental towards smaller system operators. It applies to all regulated companies, and how strongly each company is affected depends on its individual efficiency score. The current benchmark relies on a set of suitable output parameters, and it uses constant returns

[54] BNetzA (2015), *Evaluierungsbericht nach § 33 Anreizregulierungsverordnung* (Evaluation under section 33 of the Incentive Regulation Ordinance), 21 January 2015.

to scale. This way, we incentivise companies to choose the optimal company size. Firms that deviate from this optimal size indeed have lower technical efficiencies. But this holds for companies above the optimum just as well as for those below, i.e. both for firms that are too large and those that are too small.

Respondents also criticised that most companies' efficiency scores were below the arithmetic mean; this cannot actually be true, since the median efficiency score is much above the arithmetic mean. Please note that this does not necessarily mean that DSOs receive low efficiency scores for operating below the optimal company size; after all, the efficiency score reflects not only scale effects but also cost effects.

Finally, respondents argued that the shorter realisation period did not adequately consider the particularities of small and medium-sized companies. Again, we do not agree: any structural effects are addressed as part of the benchmarking exercise; they do not impact how efficiency scores are translated into potentials and targets.

We design the regulatory regime with a view to achieving the overall goals of incentive regulation. Extreme considerations around productive and allocative efficiency might jeopardise the financial viability of Austria's system operators. And while a yardstick system (which fully decouples a company's allowed from its actual costs) might deliver much more pronounced incentives, we have found a balance between the goals. Thus, we arrive at a regime with the following cornerstones: a realisation period of one-and-a-half regulatory periods; an efficiency floor; efficiencies calculated using different methodologies, which are weighted and combined into one per cost data set, the better of which is then used as efficiency score; an individual WACC for each company with clearly positive returns on equity for companies at the efficiency floor; allowed costs that are calculated for each company separately; and a new cost audit before the beginning of future regulatory periods. Overall, this makes for a balanced approach. Respondent system operators and the industry associations supported a ten-year realisation period, while keeping the five-year rhythm for cost audits, so that efficiency scores would become much less important. In line with the above considerations, we are of the view that these proposals of the industry do not optimally respond to the overall goals of incentive regulation.

We encourage companies to understand the shortened realisation period for the fourth regulatory period as a preparatory step towards possibly introducing yardstick regulation in future. Under this type of regulatory regime, a company's costs are decoupled from the reference (average or best practice) costs not only during the regulatory period but also at the beginning, when the allowed costs are set. Our decision to shorten the realisation period and thereby create a stronger incentive for efficiency is validated by several system operators' statements about their internal practices: that they merely aim to realise the annual potential identified but do not try to go further, or that they do not consider the built-in incentive in their decision-making because the efficiency target is spread over such a long period and because their costs are always included in the allowed costs at the beginning of the next period. Swiss Economics 2018 finds that higher allowed costs seem to be more important for companies than a good efficiency score. We do agree with this finding and have shortened the realisation period so as to eliminate this effect.

Following the above considerations, the formula for each company's overall efficiency target is as follows:

$$ZV = 1 - (1 - Xgen) \times \sqrt[7,5]{ES_{2018}}$$ [55]

where ES_{2018} designates the individual (weighted) efficiency score.

With an efficiency floor of 80% and a realisation period of one-and-a-half regulatory periods (i.e. 7.5 years), the maximum annual individual efficiency potential is 2.931%. Together with the general

[55] In English:
$OverallEfficiencyTarget = 1 - (1 - Xgen) \times \sqrt[7,5]{EfficiencyScore_{2018}}$

productivity growth rate, this results in a maximum overall efficiency target of 3.854% p.a.; this is below the maximum targets that were in place previously.

The annual target does not change during the fourth regulatory period. For subsequent periods, an entirely new regulatory system may be established; therefore, the efficiency scores of the fourth regulatory period do not pre-empt how gas and electricity DSOs' compensation will be handled in the future.

An efficient company's overall efficiency target corresponds to X-gen, i.e. there is the following relationship between efficiency scores and overall targets:

Efficiency score	Overall annual target
80%	3.854%
85%	3.073%
90%	2.332%
95%	1.625%
100%	0.950%

Figure 9: Relation between the efficiency score and the overall annual target

Please note that these targets apply to the controllable operational costs only (cf. chapter 4.2); capital cost is indexed with each company's individual WACC (cf. chapters 4.3.1 and 4.3.2).

8. Network operator price index (NPI)

In the interest of cost reflectiveness, costs must be indexed with an inflation factor over the course of the regulatory period. This way, we account for external cost increases (i.e. cost increases beyond the companies' control). Given the different treatment of operational expenditure (addition of a uniform operating cost factor across all companies, cf. chapter 11.1) and capital expenditure (direct CAPEX compensation, cf. chapter 4.3.2), it is the allowed OPEX only that are subject to inflation indexation.

Section 59(5) Electricity Act 2010 stipulates that the system operator inflation rate has to be derived from a network operator price index combining public indices that reflect the electricity DSOs' average cost structure.

During the third regulatory period, we calculated a network operator price index (NPI) to reflect the industry's average cost structure and we used the change in that index (ΔNPI) to account for the cost increases that electricity distribution system operators face. We continue with this practice and with the same components and weightings for this index, i.e.:

> the index of collectively agreed wages and salaries (*Tariflohnindex*, TLI), a general index, which is compiled and published by Statistics Austria. The change in this index is a proxy for the average changes in personnel costs (weighting: 57 percent).

> the consumer price index (*Verbraucherpreisindex*, VPI), published by Statistics Austria. The change in the VPI is a proxy for the average changes in other costs (weighting: 43 percent).

As an alternative to the TLI, we could use collective bargaining results as a proxy for personnel cost developments. However, in line with section 59(5) Electricity Act 2010, an appropriate sub-index would first have to be generated and published for us to be able to use it. Also, section 59(5) Electricity Act 2010 requires that the index used be representative of the average cost structure of electricity distribution system operators; we believe that for a considerable number of electricity DSOs, the collective agreement for employees of electricity suppliers (*Kollektivvertrag für Angestellte der Elektrizitätsversorgungsunternehmungen Österreichs, EVU-Kollektivvertrag*) does not fulfil this criterium. Instead,

> electricity DSOs apply various collective bargaining agreements (depending on the occupational classification of their employees: blue-collar workers, white-collar workers, civil servants), and
> at least some of them outsource a significant share of network services to third parties.

Therefore, each company's individual circumstances would have to be taken into account and individual indices would have to be generated for all of them, and these would presumably converge towards the general TLI. We therefore conclude that building exclusively on one of the collective bargaining agreements (e.g. the collective agreement for employees of electricity suppliers) would not be appropriate as they neither represent average costs nor reflect the actual situation of individual electricity DSOs, and as this approach would not comply with the requirements of section 59(5) Electricity Act 2010. Instead, we continue to apply the index of collectively agreed wages and salaries as a proxy that is valid across all regulated companies.

To calculate the annual change in the NPI (ΔNPI_t), we stick to the approach taken previously by using the most recent available figures (instead of forecasts). The consumer price index is published each month, with final numbers available about one month later (after any data corrections have taken place); the same is true for the index of collectively agreed wages and salaries, with a 3.5-month revision period. Considering the deadlines in the tariff review process and the delays inherent in the indices (in particular the TLI), the most recent numbers we can use to calculate ΔNPI_t are those of December of the previous year.

In line with the above, the changes in VPI and TLI are calculated as follows:

$$\Delta VPI_t = \frac{VPI_{01.t-2} + \ldots + VPI_{12.t-2}}{VPI_{01.t-3} + \ldots + VPI_{12.t-3}} - 1$$ [56]

$$\Delta TLI_t = \frac{TLI_{01.t-2} + \ldots + TLI_{12.t-2}}{TLI_{01.t-3} + \ldots + TLI_{12.t-3}} - 1$$ [57]

We then weigh and combine them:

$$\Delta NPI_t = 0{,}57 \times \Delta TLI_t + 0{,}43 \times \Delta VPI_t$$ [58]

9. Weighted average cost of capital (WACC)

Section 60(1) Electricity Act 2010 stipulates that the cost of capital shall comprise the reasonable cost of interest on debt and equity, taking capital market conditions and income tax expense into account. As during previous regulatory periods, we apply a WACC approach to comply with this requirement.

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[56] In English:
$$\Delta ConsumerPriceIndex_t = \frac{ConsumerPriceIndex_{01.t-2} + \ldots + ConsumerPriceInde_{12.t-2}}{ConsumerPriceIndex_{01.t-3} + \ldots + ConsumerPriceIndex_{12.t-3}} - 1$$

[57] In English:

$$\Delta IndexOfCollectivelyAgreedWages_t = \frac{IndexOfCollectivelyAgreedWages_{01.t-2} + \ldots + IndexOfCollectivelyAgreedWages_{12.t-2}}{IndexOfCollectivelyAgreedWages_{01.t-3} + \ldots + IndexOfCollectivelyAgreedWages_{12.t-3}} - 1$$

[58] In English:

$$\Delta NetworkOperatorPriceIndex_t = 0.57 \times \Delta IndexOfCollectivelyAgreedWages_t + 0.43 \times \Delta ConsumerPriceIndex_t$$

Ideally, the WACC ensures that it does not make a difference whether a company invests in the market or in regulated infrastructure. Setting the WACC too high offers incentives for over-investing in the network (known in academic literature as Averch-Johnson effect), while too low a WACC entails the risk that necessary investments in the regulated infrastructure are not carried out. Our main concern is to ensure that the Austrian network is viable in the long term and can continue to provide high-quality network services.

During the third regulatory period electricity DSOs were granted a WACC before taxes of 6.42% p.a., based on an expert study. For the fourth regulatory period, we refer to the three other regulatory regimes which E-Control is responsible for: gas TSOs (from 1 January 2017),[59] gas DSOs (for the third regulatory period, from 1 January 2018) and electricity TSOs (from 1 January 2018 also). All of them are granted a WACC of 4.88% p.a. We apply the same value to all electricity DSOs with the standard capital structure, for the entire duration of the fourth regulatory period, beginning on 1 January 2019. We base this decision on a 2016 Frontier Economics study[60] with a reference period up to the end of 2015. We do not update this study to avoid perverse incentives among the different sectors that could arise from setting different WACCs.

We use largely the same parameters as for calculating the WACC for gas TSOs:

	3rd regulatory period	**4th regulatory period**
Risk-free interest rate	3.27%	**1.87%**
Risk premium for debt capital	1.45%	**0.83%**
Equity risk premium	5.00%	**5.00%**
Unlevered beta	0.325	**0.400**
Levered beta	0.691	**0.850**
Debt ratio	60.00%	**60.00%**
Equity ratio	40.00%	**40.00%**
Corporate tax rate	25.00%	**25.00%**
Cost of equity (post tax)	6.72%	**6.12%**
Cost of equity (pre tax)	8.96%	**8.16%**
Cost of debt (pre tax)	4.72%	**2.70%**
WACC (pre tax)	6.42%	**4.88%**
WACC (**post tax**)	4.81%	**3.66%**

Figure 10: Components of the WACC in accordance with section 60 Electricity Act 2010

For investments during the regulatory period (i.e. between 2019 and 2023), an equity premium of 0.8% applies, which translates into a mark-up of 0.32% (= 0.80 x 40% equity share) and an overall WACC of 5.20% p.a. for new assets.

Mark-up on cost of equity	0.80%
WACC for new assets	5.20%
Cost of equity for new assets	8.96%

Figure 11: WACC for new assets

Below, we explain how calculate each of the parameters that together make up the WACC.

Risk-free rate

During the third regulatory period, we used the secondary market yield (Sekundärmarktrendite, SMR) for calculating this parameter. Frontier Economics 2016 recommend turning away from this practice, since this index has not been calculated or published since end of March 2015. Austrian government bonds do not make for a solid reference either because the country no longer enjoys a triple A rating. Referencing an index with longer maturities (such as the secondary market yield and its successor index, the average yield on government bonds weighted by outstanding amounts,

[59] https://www.e-control.at/documents/20903/-/-/97b2e2a6-9330-4ad2-9875-1b55a4fc6242 (German only).
[60] Frontier Economics (2016), *Bestimmung der Finanzierungskosten für Energienetzbetreiber* (Calculating the WACC for energy system operators), study commissioned by E-Control, March 2016.

UDRB) would not be adequate either: corporate finance is not constrained by the residual useful life of assets, but should focus at the cheapest sourcing strategies available. The useful life of assets is only relevant in case of project financing. For the finances of a company overall, it is much more important to keep the cost of capital in check. With these considerations in mind, we apply a five-year average of ten-year AAA bonds in the Eurozone, resulting in a risk-free rate of 1.87%.

Risk premium for debt capital (debt spread) and cost of debt

We use two references to calculate the debt spread: the yield generated by exchange-traded company bonds and European bond indices. Companies with a below-A rating are excluded because we assume that Austrian system operators have high credit ratings due to them being regulated and thanks to the characteristics of the regulatory regime. Like for the risk-free rate, we use a five-year average. Frontier Economics 2016 calculate a range of appropriate debt spreads. Since the Austrian energy suppliers' debt spreads are at the lower end or even below the range (as per their annual accounts), we stick to the lower end as well. Overall, we estimate the cost of debt to be 2.70%.

Market risk premium

Again, we base this parameter on Frontier Economics 2016, but we continue to apply a premium of 5.0% (instead of 4.4%). Thereby, we acknowledge the considerable insecurity attached to calculating it and provide regulatory stability by continuing to apply the same premium as in the previous regulatory period. Should the lower rate presented by Frontier Economics 2016 prove to be stable in the longer term, we will consider whether to adjust the risk-free rate in future regulatory periods. We would also like to point to a recent ruling by the Higher Regional Court of Düsseldorf,[61] according to which the values for the cost of equity and the risk pertaining to it used by the German regulator were too low and did not adequately reflect the unstable situation on international financial markets.

Unlevered and levered beta

In line with the methodology recommended by Frontier Economics 2016, we checked a sample of comparable companies for data availability, portion of turnover generated from network business and liquidity indicators of their stocks and then used the insight gained to delete any unsuitable companies from the sample. For details about data frequency and comparable indices as well as the adjustments made to the raw betas and the capital structure, please refer to the study itself. Based on the 'system operator only' sample and a three-year average, we apply an ungeared beta of 0.4. For the geared beta, we account for the standard capital structure of Austrian companies and corporate tax, and we apply the Modigliani Miller theorem.

As part of the stakeholder process for the regulatory regime of the fourth period, on 6 June 2018 the industry association Oesterreichs Energie submitted two presentations about their view on how to calculate the WACC (NERA 2018a[62] and BBH 2018a[63]).

NERA 2018a basically confirm that a beta of 0.4 is adequate. Their criticism focuses on the risk-free rate, the market risk premium and the debt spread, which in their view fail to consider the

[61] Higher Regional Court of Düsseldorf, 3rd Cartel Panel (2018), file number VI-3 Kart 466/16 (V).

[62] NERA (2018a), *WACC für Stromverteilnetze (2019-2023)* (Calculating the WACC for electricity distribution systems (2019-2023)), presentation of results, 6 June 2018.

[63] BBH (2018a), *Zinsgutachten Strom für 4. Regulierungsperiode* (Study on cost of capital for the fourth regulatory period in electricity), summary of BBH results, 6 June 2018.

extraordinary situation on the capital markets (illustrated by four charts on slide 4 in their presentation).

The downward trend in nominal lending rates of central banks could create the impression that we are facing an unprecedented situation. However, we have undertaken a comprehensive analysis and find that this is a misconception. Indeed, economic theories explain that this is logical and happens more often than is generally believed, especially when real rates are considered. According to economics literature, the downward trend of nominal government bond yields since the 1970s results from the independence of central banks, which focus on explicit inflation targets.

NERA's argument in favour of a higher market risk premium relies on a much shorter reference period (2000-2016), and on the interest rate spread between Euribor and government bonds. Therefore, NERA's assessment solely reflects the debt spread on the interbank market. It is, however, unclear whether these numbers are relevant for system operators (which constitute secure investment opportunities).

The increasing stock market yield shown in NERA 2018a seems to be derived from implicit market risk premiums, i.e. from expectations rather than actual yields. Overall, we appreciate that NERA use both historical data and forecasts to calculate the market risk premium. Indeed, the Higher Regional Court of Düsseldorf in its above-mentioned ruling points out that current developments on the capital markets should always factor into considerations. However, Frontier Economics 2016 warn that forecasts must be used cautiously. And the Court itself makes particular reference to the opinions of experts heard in the proceedings and confirms that ex-ante approaches, though they have been gaining favour lately, are not necessarily superior to ex-post analyses.

On slide 6, NERA reference market yield data from the Deutsche Bank Monthly Report of February 2018 and use these to tie the contraction on the US stock market to the Fed's interest rate hikes. In our view, this is an unfair representation: Deutsche Bundesbank uses the implicit cost of equity and stock premiums as leading indicator for the market overheating or stock market bubbles forming, i.e. to gauge the stability of financial markets. Also, the information presented is a snapshot (because it is taken from a monthly report).

The historical total market return (TMR) approach used by NERA 2018a is confusing: their market risk premium is the result of a linear relation with a constant of 7.81% and the risk-free rate multiplied by -1.05. If the risk-free rate were to reach about 7.5%, this would mean a market risk premium of zero. If we subscribed to this line of thinking, it would mean that investors would not expect additional returns from risky investments in times of high nominal risk-free rates (e.g. as observed in the late 1980s); indeed, they would be willing to pay for taking on risks (cf. the returns during the Weimar Republic). We therefore conclude that either the regression or the basic theoretical assumptions of the calculations presented by NERA 2018a must be faulty. Also, Dimson, Marsh and Saunton, authors of the key publication on calculating historical market risk premium, have published a new study (DMS 2018[64]). In it, they analyse the relation between the real risk-free rate and the real return on equity. Their findings, drawing on a sample covering 21 countries and a 118-year reference period, contradict those of NERA. DMS 2018 find that low real risk-free rates engender low returns for all risk-intensive investments; only unexpected rate hikes or drops cause brief spikes in returns. In their reply, NERA argue that actual inflation rates came as a surprise to investors, which is why the ensuing stock market returns and market risk premiums could not be taken to represent the current situation on the capital markets.[65] This line of argument exposes the weaknesses of the forecast models preferred by NERA (DGM and polls): if investors can indeed be surprised by a normal development like inflation, markets are clearly not functioning well and expectations are not reliable.

[64] Dimson, Marsh & Staunton (2018), Credit Suisse Global Investment Returns Yearbook 2018 – Summary Edition.

[65] NERA (2018b), *WACC für Stromverteilnetze (2019-2023)* (Calculating the WACC for electricity distribution systems (2019-2023)), study commissioned by Oesterreichs Energie, 15 June 2018.

We stick to our assumption that expectations under the dividend growth model (DGM) are excessive and that investors are then surprised by the actual dividend yield falling short of their expectations. We also point to the academic literature in this context, which promotes the idea that analysts tend to overestimate dividends for the next year, let alone those for longer future time periods.

Unfortunately, NERA do not lay out which theoretical element in their capital asset pricing model explains their assumed inverse relationship between risk-free rate and market risk premium. The risk-free rate does not permit sufficiently reliable forecasts of market risk premiums; if we aim to determine a risk premium that develops over time, there are other, better models and explanations that should be referenced. For instance, Cochrane 2005 demonstrates that market risk premiums tend to be higher in periods of volatile market developments, following market crashes and during recession periods; lower volatility, price hikes and booming markets produce lower risk premiums.[66] Given that neither the expected market yield nor the expected dividend growth are accurate predictors for stock prices, it would be unreasonable to expect the risk-free rate be the single factor that can predict the market risk premium. Quantitative easing has the European Central Bank buying up risky assets to lower risk premiums across the board and stimulate investments. If this would drive actual (not expected) risk premiums on the stock markets up, this would render the intervention pointless in the first place. Instead, successful quantitative easing leads to lower market risk premiums and market yields. It would not be logical to expect the market risk premium to rise or the market yield to go sideways.

In addition, the market yield projected by the consultant is out of reach for the foreseeable future, regardless of whether it relies on an implicit assessment or a shorter reference period. The reasons for this abound: as a matter of example, we point to a recent publication by McKinsey Global Institute[67] which lays out why it will hardly be possible to replicate the market yields observed over the past 30 years and how these latter are considerably above the long-term average (over the last 100 years). McKinsey Global Institute conclude that the next 20 years will bring real market yields in the order of 4%-6.5% for US and 4.5%-6% for European equities, depending on the growth scenario (slow growth vs. growth recovery). The yields seen in recent years were only possible because several economic trends coincided: inflation and interest rates were at abnormally high (nominal) levels before and then dropped sharply; global GDP growth was strong; demographic developments weighed in positively; productivity grew; emerging markets expanded particularly strongly; corporate taxes were down; automation increased; the global supply chain progressed etc.

As far as the risk-free rate is concerned, our own value is within the range calculated by NERA.

For the cost of debt, NERA estimate a rate of 3.29% p.a. A brief cross-check with actual numbers immediately reveals that their calculation faces major shortcomings. For instance, integrated company KELAG state in their 2017 annual report that their average cost of debt is 2.7% (or 2.9% if we correct for their EIB-supported debt share). OMV, a company exposed to considerable international risk, lists an average cost of debt of 2.6%. As opposed to these two, companies under the regulatory regime face no country risk and no volume risk (as the latter is taken care of by the regime) and should thus be able to get much lower interest rates on their debt.

NERA also present an international comparison. However, they put different currencies with different inflation rates side by side (Switzerland, Norway, Sweden, Great Britain and the Eurozone); a comparison on real values would be more useful. Also, the analysis fails to state the WACC reference date.

BBH mainly criticise that in setting the regulatory regime for gas DSOs (third period), and for gas and electricity TSOs, we did not explicitly refer to the extraordinary circumstances created by the economic and financial crisis. They also point out that we did not acknowledge an inverse relation between the risk-free rate and the market risk premium, and that we did not apply recommendations concerning companies' credit ratings. Their argument here is the complaint

[66] Cochrane (2005), Financial markets and the real economy, NBER Working Paper Series 11193.
[67] McKinsey Global Institute (2016), Diminishing returns: why investors may need to lower their expectations.

against the German regulator's decision filed by several German system operators with the Higher Regional Court of Düsseldorf. In addition, BBH argue that the relevant market for investors is the domestic market, not the global one. If based on a ten-year average of Austrian government bonds with 10-year maturities, the risk-free rate would be 2.24% p.a.

We maintain that Austrian government bonds no longer adequately reflect the risk-free rate because Austria has lost its AAA rating. By switching from the secondary market yield / the average yield on government bonds weighted by outstanding amounts to the triple A index of European government bonds, we account for BBH's call to reference bonds with 10-year maturities. As for the reference period, the relevant German ordinance indeed specifies a ten-year average to be used; however, some other European countries apply markedly shorter periods (cf. Estonia, Finland, Greece, Italy, the Netherlands, Poland, Portugal).[68]

BBH take a hybrid approach that combines a historical perspective, an implicit market risk premium and a plausibility check via TMR to calculate the cost of equity and the market risk premium. They conclude that a market risk premium of 6.17% (an average between a historical German market risk premium and an implicit one for Austria) would be appropriate. Together with the above-mentioned risk-free rate, this would lead to an adequate market yield. We point to the verdict by the Higher Regional Court of Düsseldorf, whereby neither the ex-ante model (implicit market risk premium) nor the TMR approach are superior or lead to better, empirically more valid results than other methods. Also, the TMR approach requires that the current risk-free rate be subtracted; BBH subtract a historical average risk-free rate instead. What is more, during the hearing before the court, expert witness Dr J. stated that a value at the upper end of the range that results from the historical approach should be chosen to account for the fundamental structural change that the financial and capital markets are undergoing. Frontier Economics 2016 calculate a range of 3.2%-4.4% for the historical market risk premium and recommend settling for a value at the upper end of this range. Our own value, at 5%, is easily above this range and should be interpreted in light of the above discussion on the market risk premium.

To calculate the beta, BBH use a one-year average and arrive at a result of 0.42.

Overall, BBH propose a cost of equity before tax of 10.33%; this is even higher than the cost of equity during the third regulatory period. Their total market return is 7.75%. As for referencing the domestic or European market, we point out that the historical real stock market return between 1900 and 2017 was about 1% in Austria and below 4.5% in Europe overall (cf. DMS 2018). The results delivered by the TMR approach would need to be double-checked, bearing in mind that nominal risk-free rates and inflation are both low at the moment. However, BBH do not perform any such check.

For the debt spread, BBH calculate the ten-year average of the credit spread for risky, A minus rated investments with 10-year maturities. Frontier Economics 2016 use a five-year average and A-rated investments instead. Overall, they propose a debt spread of 0.98% and, after accounting for the risk-free rate, a cost of debt of 3.42% p.a. Please refer to our arguments concerning NERA's statements about cost of debt presented above.

We do not agree with the allegation that our decision to keep the market risk premium at 5% is unfounded or mechanical (cf. the verdict handed down by the Higher Regional Court of Düsseldorf); the values we use for cost of equity and cost of debt are the result of a thorough analysis, with the latter having been double-checked against the actual cost of debt that Austrian energy suppliers currently report. We therefore maintain a WACC before tax of 4.88% for electricity DSOs during the fourth regulatory period. This is the rate that applies for a company with an average efficiency score and that forms the reference point for calculating each company's individual WACC (cf. chapters 4.3.1 and 6.6).

[68] CEER (2017), CEER Report on Investment Conditions in European Countries.

The industry associations and individual system operators argue that the cost of capital should be raised. We categorically exclude this as it would contradict our intention to avoid perverse incentives arising from different WACCs for electricity and gas. The first relevant WACC had to be determined in time for it to be applied from 1 January 2017; this means that our reference period ends at year-end 2015. Regulatory stability would require that we keep setting the parameters of the regime on a historical basis also in future regulatory periods; this holds in particular for the reference period over which the risk-free rate is averaged. If we were to abandon the established practice of averaging over the five most recent years for which data are available and were to instead switch to forecasts, this would contradict the concept of setting a WACC that is balanced in the long term as required by section 60 Electricity Act 2010.

10. Regulatory asset base (RAB)

According to section 60(4) Electricity Act 2010, the regulatory asset base consists of the sum of intangible assets and tangible assets minus the system admission and provision charges collected (consumer prepayments for installation costs) that are recorded as liabilities and any goodwill, all of which as shown on the balance sheet.

Regulatory asset base
Total immaterial assets
Total fixed assets
Total leased assets
- Prepayments for installation costs (not part of RAB)
- Restructuring / goodwill
Other corrections
Regulatory asset base

Figure 12: Regulatory asset base

Calculating the regulatory asset base as shown above has proven appropriate during the third regulatory period, which is why we maintain it for the fourth period. Facilities under construction are taken into account as tangible assets. Please note that under the title ‘other corrections’, we adjust for subsidised loans, which are included at their actual subsidised cost of capital (cf. section 60(1) Electricity Act 2010). Further examples of ‘other corrections’ are those concerning fixed assets, e.g. as a result of unbundling.

11. Expansion factors

Incentive regulation means that the allowed costs are decoupled from actual costs, i.e. they can diverge. A new audit, based on which the allowed costs are freshly determined, normally only occurs before the outset of a new regulatory period. However, the scope of the operators’ mandate – number of consumers to be connected etc. – might develop during a regulatory period, and we use so-called expansion factors to account for such developments. This way, regulated companies can be sure that any investments they need to make in response to such trends will be covered. However, expansion factors are not designed to track all cost increases during a regulatory period. After all, incentive regulation is specifically meant to temporarily decouple allowed costs from current developments.

For the second and third regulatory periods, we used two expansion factors (an operating cost factor and an investment factor) to integrate changes in the operators’ mandate that occurred during the regulatory period.

For the fourth period, we follow the same approach as for gas DSOs and apply an individual WACC for each company; this already covers investments, i.e. we do not need the investment factor anymore because the regulatory regime already provides for an annual re-evaluation of CAPEX (cf. chapter 4.3.2).

We keep the operating cost factor as in the previous regulatory period (cf. chapter 11.1).

11.1. Operating cost factor

The operating cost factor, in its redesigned form for the fourth regulatory period, is used for the first time to set the 2019 grid charges (i.e. for the initial year of the fourth regulatory period) and reflects the change in the regulated companies' mandate (as far as operating costs are concerned) in 2017 compared with 2016 (the audited year).

For the second and third regulatory periods, we used an operating cost factor that was based on empirical observations. We identified significant cost drivers in the 2008 and 2013 audited costs, among them grid kilometres. The operating costs calculated for low voltage grid kilometres were combined with weighting factors to derive the costs for grid kilometres at the medium and high voltage levels. We keep the same approach and weighting factors for the fourth regulatory period.[69]

In principle, we use the total operating costs of network levels 3-7, but we correct some companies' data to ensure that additional OPEX from rendering transmission services at network level 3, from rolling out smart meters or from re-evaluations are excluded.

A linear regression calculation with the weighted real grid kilometres at low, medium and high voltage and the total number of metering points (withdrawing (including interruptible points) + injecting + 2 * bidirectional) as parameters can explain the entire residual OPEX.

In formal terms, this can be expressed as follows:

$$OPEX\ abzgl.Bereinigungen =$$

$$\beta_0 + \beta_1 * gewichtete\_reale\_Leitungslänge + \beta_2 * Zählpunkte\_gesamt + \varepsilon$$ [70]

where

β_j are the coefficients (to be estimated via OLS) and

ε is the error term.

This calculation leads to the following result[71]:

[69] Please note that the selected analytical approach merely enables us to calculate average costs. In principle, a panel data estimation would be preferable when it comes to estimating cost increases during a particular period. However, we stick with the empirical analysis for the time being and do not use the data set from our X-gen calculation to switch to a different approach.

[70] In English:

$$OPEXMinusCorrections = \beta_0 + \beta_1 * WeightedRealGridKilometres + \beta_2 * TotalMeteringPoints + \varepsilon$$

[71] The regression results were calculated using the package *stargazer: Well-Formatted Regression and Summary Statistics Tables* in *R* (Hlavac, 2018); details: https://CRAN.R-project.org/package=stargazer.

```
================================================
                        Abhängige Variable:
                   ----------------------------
                 OPEX abz. Bereinigungen * 1000
------------------------------------------------
Gew. reale Leitungsl.      1.689,160***
                            (149,994)

Zählpunkte gesamt             55,373***
                              (6,019)

Constant                   2.135.219,000*
                          (1.236.961,000)

------------------------------------------------
Beobachtungen                     38
R2                               0,968
Adjusted R2                      0,967
Residual Std. Fehler    6.592.204,000 (df = 35)
F Statistik            537,297*** (df = 2; 35)
================================================
Hinweis:            *p<0,1; **p<0,05; ***p<0,01
```

Figure 13: Result of the operating cost factor calculation

In line with these calculations, we set the following rates for OPEX increases to be accounted for by the operating cost factor:

> 55.37 EUR per metering point (regardless of network level, injection/withdrawal/bidirectional and conventional/smart);
> 1,689.16 EUR per kilometre of actual low-voltage system length;
> 1,891.86 EUR (1,689.16 x 1.12) per kilometre of actual medium-voltage system length;
> 4,932.35 EUR (1,689.16 x 2.92) per kilometre of actual high/extra-high voltage system length.

We apply the same rate for all additional metering points, regardless of whether they are equipped with conventional or smart meters. The reference year for charting the total number of a company's metering points is always the year of the cost audit. In formal terms, the operating cost factor (in this case, for 2019) is calculated as follows:

$$\begin{aligned}
&Betriebskostenfaktor_{2019} = \\
&(Zählpunkte_{2017} - Zählpunkte_{2016}) * 55{,}37 + \\
&(Systemlänge_NSP_{2017} - Systemlänge_NSP_{2016}) * 1.689{,}16 + \\
&(Systemlänge_MSP_{2017} - Systemlänge_MSP_{2016}) * 1.891{,}86 + \\
&(Systemlänge_HHSP_{2017} - Systemlänge_HHSP_{2016}) * 4.932{,}35
\end{aligned}$$ [72]

where

[72] In English:

$$\begin{aligned}
OperatingCostFactor_{2019} = {} & (MeteringPoints_{2017} - MeteringPoints_{2016}) * 55.37 + \\
& (SystemLengthLowVoltage_{2017} - SystemLengthLowVoltage_{2016}) * 1{,}689.16 + \\
& (SystemLengthMediumVoltage_{2017} - SystemLengthMediumVoltage_{2016}) * 1{,}891.86 + \\
& (SystemLengthHighExtraHighVoltage_{2017} - SystemLengthHighExtraHighVoltage_{2016}) * 4{,}932.35
\end{aligned}$$

$$Zählpunkte = \sum_{Netzebene=}^{7} Entnehmer\ inkl. unterbrechbare + Einspeiser + 2xZählpunkte\ in\ beide\ Richtungen \quad (73)$$

and

$$Systemlänge\_HHSP = Systemlänge\_Hochspannung + Systemlänge\_Höchstspannung \quad (74)$$

As the operating cost factor is intended to reflect the OPEX development that results from changes in a company's mandate during the regulatory period, it can be positive just as well as negative (in the event that lines are decommissioned or that the number of registered metering points falls). However, as one company pointed out during the consultation, if it is fewer interruptible metering points that we are seeing, the situation is different: a reduction in interruptible points does not entail dismantling of infrastructure, which is why we cannot expect it to reduce a company's costs and we do not enter it into the operating cost factor.

The reference year is always the cost audit year, i.e. 2016.

Operating cost factor for smart meters

During the third regulatory period, we used a cost-plus model for OPEX related to smart metering. This turned out to be cumbersome and inefficient: it is difficult to decide which part of a company's OPEX is made up of additional costs and which part of it is already accounted for in the allowed costs. Heated annual discussions with the regulated companies invariably ensued; auditing consumed excessive time and effort; and the companies themselves displayed widely ranging interpretations of what would be counted as additional smart meter related costs and what would not. Also, such a cost-plus element does not incentivise regulated companies to seek efficiencies in rolling out smart meters.

Considering the above, we move away from the cost-plus approach. To ensure that additional OPEX from smart meter roll-out are adequately reflected, we grant companies a predefined unit cost per smart meter. We factor in an expanding and a contracting component, both of which rely on a company's roll-out ratio. This ratio is calculated at the end of each financial year, and it represents the number of smart meters a company actually has as a share in the total number of smart meters that it aims to have in the end. Also, we account for different approaches to operating smart meters (s. below).

Based on data collected from and cross-checked with the companies themselves, we calculate the median OPEX per installed smart meter. During the installation phase, we expect these costs to be higher; we explicitly account for this via a multiplier. This process results in an additional OPEX of EUR 16.39 per smart meter during the installation phase. However, smart meters immediately enable companies to realise efficiencies and cost savings, and to share these savings with customers, the unit cost we grant declines as a company's roll-out ratio increases.

[73] In English:

$$TotalMeteringPoints = \sum_{NetworkLevel=3}^{7} WithdrawingPointsIncludingInterruptiblePoints + InjectingPoints + 2xBidirectionalPoints$$

[74] In English:

$$SystemLengthHighExtraHighVoltage = SystemLengthHighVoltage + SystemLengthExtraHighVoltage$$

On the other hand, calculations show that we must expect the additional OPEX to be slightly higher than the cost savings. The difference between the two, EUR 1.46, is gradually added to the unit cost as the roll-out progresses.

In formal terms, this is:

$$Betriebskostenfaktor\ Smart\ Metering = 16{,}39 * (1 - Ausrollungsgrad\ in\ \%) + 1{,}46 * (Ausrollungsgrad\ in\ \%)$$ [75]

As for the overall operating cost factor, we correct for the systemic time lag.

In addition to the above uniform considerations, companies pursue a variety of smart meter operating approaches with differing degrees of outsourcing. The costs for such outsourcing are not part of CAPEX, i.e. are not accounted for under direct CAPEX compensation, and must therefore be added to the unit costs per smart meter discussed in this section. Companies that outsource data transmission receive an additional EUR 4.75 per smart meter, while those that fully outsource smart metering are granted a EUR 24.98 top-up on the smart meter unit cost. At the beginning of the fourth regulatory period, regulated companies must disclose, and we will verify, which of these approaches they pursue. They cannot be re-categorised (and receive a higher compensation) during the period.

As we collect more and more data, we will continuously evaluate whether the expanding and contracting elements described above are indeed adequate. Should this no longer be the case, we will correct the above values even if this means adjustments during the regulatory period. This has been discussed and agreed with the parties to the procedure (cf. the minutes of the fourth expert meeting).

11.2. Incentives for efficient investments

During the fourth regulatory period, increased CAPEX are accounted for through direct CAPEX compensation, enlarged OPEX by adding the operating cost factor. Neither of them is subject to efficiency targets or the system operator price index.[76] With respect to investments made during the fourth regulatory period, we assume that these are of average efficiency. Therefore, we choose a uniform rate for these years. However, all investments will be assessed within the next efficiency benchmark, ahead of the fifth regulatory period, and will then be subject to the company's individual WACC. We are thus working with a moving delimitation between ‘old’ and ‘new’ investments and relative changes in costs (OPEX and CAPEX) will affect the efficiency score. This way, we incentivise companies to invest efficiently.

11.3. Systemic time lag

Using the most recent available data (financial accounting and technical) creates a gap as the actual costs in the year when the new rates apply are likely to have changed in the meantime (t-2 lag). For instance, both the 2019 operating cost factor and RAB rely on data from 2017, but we can safely assume that OPEX and CAPEX are not the same in 2019 as they were two years earlier. The same is true for the non-controllable costs under section 59(6) Electricity Act 2010.[77] This systemic time lag could detain companies from investing because they only recover their costs two years

[75] In English:

$$SmartMeteringOperatingCostFactor = 16.39 * (1 - RollOutRatioIn\%) + 1.46 * (RollOutRatioIn\%)$$

[76] Targets as defined in section 59(2) Electricity Act 2010 refer to the general productivity growth rate and the individual efficiency potential.

[77] We would like to explicitly point out that the two-year correction discussed in this chapter does not extend to controllable costs, which are already accounted for in the regulatory formula.

later, when new investments are included as part of direct CAPEX compensation and the parameters for the operating cost factor are updated. This means that companies must pre-finance these investments, i.e. they are exposed to a certain interest rate and liquidity risk. Vice versa, savings are not passed on immediately either, creating elevated charges for customers (at least for some time).

The two-year time lag could mean rates that are too low for companies whose mandates are steadily growing or it could mean rates that are too high for customers of companies whose mandates are steadily shrinking. To protect both of them, we correct for the difference between the t-2 data and the current data once these latter become available. We introduced this as part of the regulatory regime for the third period and continue with the same idea. The correction for the 2019 and 2020 rates relies on the specification applied for the investment and operating cost factors during the third regulatory period, i.e.

$$\begin{aligned} Aufrollung_{2019} = {} & BKFaktor_{2019}^{bish.Spezifikation} - BKFaktor_{2017}^{bish.Spezifikation} \\ & + InvestFaktor_{2019}^{bish.Spezifikation} - InvestFaktor_{2017}^{bis\ \ .Spezifikation} + nbK_{2017} \\ & - nbK_{2015} \end{aligned}$$ [78]

For the rates from 2021 onwards, we follow the same logic but use the new specification of the operating cost factor and the newly introduced direct CAPEX compensation. The correction includes the mark-up on the CAPEX compensation so that companies can benefit from it for the entire duration of the regulatory period. In formal terms, this is:

$$\begin{aligned} Aufrollung_{t} = {} & BKFaktor_{t}^{neue\ Spezifikation} - BKFaktor_{t-2}^{neue\ Spezifikation} \\ & + Kapitalkostenabgl._{t}^{inkl.Mark-up} - Kapitalkostenabgl._{t-2}^{inkl.Mark-up} + nbK_{t-2} \\ & - nbK_{t-4} \end{aligned}$$ [79]

12. Regulatory account

When calculating the system charges, we rely on the most recent available data on the volume transported (cf. section 61 Electricity Act 2010). However, the companies' revenues are calculated by multiplying these rates by the volumes actually transported in the respective year. This results in a difference between the revenue assumptions that we base our ordinance on (because these are derived from the most recent available data, not the actual, current data) and the actual revenues generated. This difference can be positive or negative, i.e. it can lead to either excessive or insufficient cost recovery for the companies.

To deal with this issue, section 50(1) Electricity Act 2010 specifies that any differences between the actual revenues collected and the assumed revenues in the electricity system charges

[78] in English:

$$Correction_{2019} = OperatingCostFactor_{2019}^{PreviousSprecification} - OperatingCostFactor_{2017}^{PreviouslSprecification} + InvestmentCostFactor_{2019}^{PreviousSpecification} - InvestmentCostFactor_{2017}^{PreviousSpecification} + NonControllableCosts_{2017} - NonControllableCosts_{2015}$$

[79] In English:

$$Correction_{t} = OperatingCostFactor_{t}^{NewSpecification} - OperatingCostFactor_{t-2}^{NewSpecification} + DirectCAPEXCompensation_{t}^{IncludingMarkUp} - DirectCAPEXCompensation_{t-2}^{IncludingMarkUp} + NonControllableCosts_{t-2} - NonControllableCosts_{t-4}$$

ordinance must be taken into account when establishing the allowed costs for the next charges ordinances.

During the third regulatory period we introduced the regulatory account to enable us to account for these differences, which maintain for the fourth period.

13. Incentives for research and development

In the interest of modernising system operation and contributing to the Austrian government's climate and energy strategy, we introduce an incentive mechanism for research and development. The industry association Oesterreichs Energie, individual system operators and the Austrian Economic Chamber and Federal Chamber of Labour, as statutory parties to the regulatory process, were involved in designing this mechanism. Industry representatives underlined that they mainly needed clarity on the regulatory framework; we believe that fixing the regulatory regime for the fourth period adequately addresses this wish. The Austrian Economic Chamber and the Federal Chamber of Labour generally maintained that the WACC provided sufficient incentives, in particular since we apply a mark-up for new investments. Further topping up this mark-up for particular R&D investments was out of the question since that would require E-Control to pick ex ante which technologies to push. In line with these comments, we do not follow this avenue.

Oesterreichs Energie and a number of system operators proposed stopping the practice of subtracting subsidies for R&D projects from the companies' allowed costs. We follow this suggestion so as to incentivise system operators to apply for such subsidies and invest time and effort in the relating projects (project management, application procedures etc.).

14. Regulatory formula

In this section, we summarise the contents of this document in formal terms.[80] By way of example, we present the equations for the 2019 allowed costs (that are then translated into 2019 system charges). Please note that the below equations do not differentiate between network levels; this is purely for the sake of clarity. After all, section 59(1) and (7) Electricity Act 2010 requires that the allowed costs be calculated for each network level separately. The representation below is simplified in this regard, but the calculations work the same way if applied to the individual network levels or to the years after 2019.

[80] We reserve the right to correct any lack of clarity or errors in the equations presented in this document in accordance with the principles presented.

2019 allowed costs

German formula

$$K_{2019}^{Basisentgelte} = OPEX_{2018}^{Pfad} \times (1 + \Delta NPI_{2019}) \times (1 - ZV_{4.Periode}) + Kapitalkostenabgleich_{2019} \pm BK.Faktor_{2019} + nbK_{2017} \pm Regulierungskonto_{2019} \pm Aufrollung_{2019} - BKZ_{2017} - ME_{2017} - sonst.Entgelte_{2017}$$

For companies with 31 December as their balance sheet date, this means:

$$OPEX_{2018}^{Pfad} = (OPEX_{2016} - nbK_{2016}) \times \prod_{t=2017}^{2018} [(1 + \Delta NPI_t) \times (1 - Xgen_{4.Periode})]$$

For companies with 31 March as the balance sheet date, the equation must be adjusted as follows:

$$OPEX_{2018}^{Pfad} = (OPEX_{2016} - nbK_{2016}) \times (1 + \Delta NPI_{2016})^{0,75} \times (1 + \Delta NPI_{2017}) \times (1 + \Delta NPI_{2018}) \times (1 - Xgen_{4.Perio} \quad)^{2,75}$$

The same holds for other balance sheet dates.

$$Kapitalkostenabgleich_{2019} = Afa_{2017} + RAB_{Vermögen\ bis\ 2016}^{2017} \times WACC_{eff} + RAB_{Vermögen\ ab\ 2017}^{2017} \times 4{,}88\%$$

$$\Delta NPI_{2019} = 43\% \times \Delta VPI_{2019} + 57\% \times \Delta TLI_{2019}$$

where

$$\Delta VPI_{2019} = \frac{VPI_{01.2017} + \cdots + VPI_{12.2017}}{VPI_{01.2016} + \cdots + VPI_{12.2016}} - 1$$

$$\Delta TLI_{2019} = \frac{TLI_{01.2017} + \cdots + TLI_{12.2017}}{TLI_{01.2016} + \cdots + TLI_{12.2016}} - 1$$

$$ZV = 1 - \sqrt[7,5]{\frac{K_{2023}}{K_{2018}}} = 1 - \sqrt[7,5]{\frac{K_{2018} \times (1 - Xgen)^{7,5} \times ES_{2018}}{K_{2018}}} = 1 - (1 - Xgen) \times \sqrt[7,5]{ES_{2018}}$$

where

$$K_{2023} = K_{2018} \times (1 - ZV)^{7,5}$$

$$BK.Faktor_{2019} = Betriebskostenfaktor\ f\text{ür}\ 2019$$

where

$$BK.Faktor_{2019}$$

$$= (Z\ddot{a}hlpunkte_{2017} - Z\ddot{a}hlpunkte_{2016}) \times 55{,}37 + (Gew.Systeml\ddot{a}nge_{2017} - Gew.Systeml\ddot{a}nge_{2016}) \times 1.689{,}16$$

while excluding any falling numbers of interruptible metering points.

$$nbK_{2017} = nicht\ beeinflussbare\ Kosten\ des\ Gesch\ddot{a}ftsjahres\ 2017$$

$$Regulierungskonto_{2019} = Abweichungen, welche\ im\ Rahmen\ des\ Regulierungskontos\ ber\text{ü}cksichtigt\ werden$$

$$Aufrollung_{2019} = Aufrollung\ zur\ Beseitigung\ des\ systemimmanenten\ Zeitverzugs$$

$BKZ_{2017} = Auflösung\ von\ Baukostenzuschüssen\ des\ Geschäftsjahres\ 2017$

$ME_{2017} = Messerlöse\ des\ Geschäftsjahres\ 2017$

$sonst.Entgelte_{2017} = Erlöse\ aus\ sonstigen\ Entgelten\ gemäß\ §11\ SNE.VO\ idgF$

<u>2019 allowed costs</u>

<u>English translation</u>

$$Costs_{2019}^{BasisForCharge} = OPEX_{2018}^{Allowed} \times (1 + \Delta NetworkOperatorPriceIndex_{2019}) \times (1 - OverallEfficiencyTarget_{4thPe}\quad) + DirectCAPEXCompensation_{2019} \pm OperatingCostFactor_{2019} + NonControllableCosts_{2017} \pm RegulatoryAccount_{2019} \pm Correction_{2019} - PrepaymentsForInstallationCosts_{2017} - MeteringCharges_{2017} - SupplementaryServiceCharges_{2017}$$

For companies with 31 December as their balance sheet date, this means:

$$OPEX_{2018}^{Allowed} = (OPEX_{2016} - NonControllableCosts_{2016}) \times \prod_{t=201}^{2018} [(1 + \Delta NetworkOperatorPriceIndex_t) \times (1 - Xgen_{4thPeriod})]$$

For companies with 31 March as the balance sheet date, the equation must be adjusted as follows:

$$OPEX_{2018}^{Allowed} = (OPEX_{2016} - NonControllableCosts_{2016}) \times (1 + \Delta NetworkOperatorPriceIndex_{2016})^{0.75} \times (1 + \Delta NetworkOperatorPriceIndex_{2017}) \times (1 + \Delta NetworkOperatorPriceIndex_{2018}) \times (1 - Xgen_{4thPeriod})^{2.75}$$

The same holds for other balance sheet dates.

$$DirectCAPEXCompensation_{2019} = Depreciation_{2017} + RAB^{2017}_{AssetsUpTo2016} \times WACC_{Individual} + RAB^{2017}_{AssetsFrom2017} \times 4.88\%$$

$$\Delta NetworkOperatorPriceIndex_{2019} = 43\% \times \Delta ConsumerPriceIndex_{2019} + 57\% \times \Delta IndexOfCollectivelyAgreedWages_{2019}$$

where

$$\Delta ConsumerPriceIndex_{2019} = \frac{ConsumerPriceIndex_{01.2017} + \cdots + ConsumerPriceIndex_{12.2017}}{ConsumerPriceIndex_{01.2016} + \cdots + ConsumerPriceIndex_{12.2016}} - 1$$

$$\Delta IndexOfCollectivelyAgreedWages_{2019} = \frac{IndexOfCollectivelyAgreedWages_{01.2017} + \cdots + IndexOfCollectivelyAgreedWages_{12.2017}}{IndexOfCollectivelyAgreedWages_{01.2016} + \cdots + IndexOfCollectivelyAgreedWages_{12.2016}} - 1$$

$$OverallEfficiencyTarget = 1 - \sqrt[7.5]{\frac{Costs_{2023}}{Costs_{2018}}} = 1 - \sqrt[7.5]{\frac{Costs_{2018} \times (1 - Xgen)^{7.5} \times EfficiencyScore_{2018}}{Costs_{2018}}} = 1 - (1 - Xgen) \times \sqrt[7.5]{EfficiencyScore_{2018}}$$

where

$$Costs_{2023} = Costs_{2018} \times (1 - OverallEfficiencyTarget)^{7.5}$$

$$OperatingCostFactor_{2019} = operating\ cost\ factor\ for\ 2019$$

where

$$OperatingCostFactor_{2019}$$

$$= (MeteringPoints_{2017} - MeteringPoints_{2016}) \times 55.37 + (WeightedSystemLength_{2017} - WeightedSystemLength_{2016}) \times 1{,}689.16$$

while excluding any falling numbers of interruptible metering points.

$$NonControllableCosts_{2017} = non\ controllable\ costs\ of\ the\ 2017\ business\ year$$

$$RegulatoryAccount_{2019} = deviations\ recorded\ in\ the\ regulatory\ account$$

$$Correction_{2019} = correction\ for\ the\ systemic\ time\ lag$$

$$PrepaymentsForInstallationCosts_{2017} = prepayments\ by\ customers\ towards\ installation\ costs\ made\ during\ the\ 2017\ business\ year$$

$$MeteringCharges_{2017} = metering\ charges\ collected\ during\ the\ 2017\ business\ year$$

$$SupplementaryServiceCharges_{2017} = supplementary\ service\ charges\ according\ to\ section\ 11\ Electricity\ Charges\ Ordinance\ as\ last\ amended$$

The 2020 allowed costs are established in the same way.

15. Transitioning to the next regulatory period

Information is not public

16. References

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17. Annex 1

List of regulated companies

001 Netz Burgenland GmbH
002 Wiener Netze GmbH
004 Netz Oberösterreich GmbH
005 LINZ NETZ GmbH
006 Wels Strom GmbH
007 Energie Ried GmbH
008 Energienetze Steiermark GmbH
010 Salzburg Netz GmbH
011 Stromnetz Graz GmbH & Co KG
012 Vorarlberger Energienetze GmbH
013 TINETZ-Stromnetz Tirol AG
014 Netz Niederösterreich GmbH
015 Innsbrucker Kommunalbetriebe AG
016 KNG-Kärnten Netz GmbH
017 Energie Klagenfurt GmbH
018 Energieversorgung Kleinwalsertal Ges.m.b.H.
020 Feistritzwerke-STEWEAG-GmbH
021 E-Werk Gösting Stromversorgungs GmbH
022 Stadtwerke Judenburg AG
023 Stadtwerke Kapfenberg GmbH
024 Stadtwerke Bruck a. d. Mur GmbH
026 Stadtwerke Mürzzuschlag Ges.m.b.H.
027 Elektrizitätswerk der Stadtgemeinde Kindberg
028 Stadtwerke Köflach GmbH
047 Elektrizitätswerk Perg GmbH
049 Elektrizitätswerke Reutte AG
053 Elektrizitätswerke Frastanz GmbH
101 Kraftwerk Haim KG
109 Montafonerbahn AG
119 Stadtgemeinde Amstetten, Inhaberin der nicht prot. Fa. "Stadtwerke Amstetten"
121 Stadtwerke Feldkirch
123 Stadtwerke Hall in Tirol Ges.m.b.H.
124 Stadtwerke Hartberg Energieversorungs-Ges.m.b.H.
126 Stadtwerke Kitzbühel
127 Stadtwerke Kufstein Gesellschaft m.b.H
129 Stadtwerke Schwaz GmbH
131 Stadtwerke Voitsberg GmbH
132 Stadtwerke Wörgl Ges.m.b.H.

18. Annex 2

High-level meetings

1st high-level meeting, 26 January 2018	E-Control presentation: regulatory regime for electricity DSOs, fourth period
	Oesterreichs Energie presentation: designing the regulatory regime for the fourth period
2nd high-level meeting, 26 February 2018	E-Control presentation: 2nd high-level meeting on the fourth regulatory period in electricity
3rd high-level meeting, 16 April 2018	E-Control presentation: 3rd high-level meeting on the fourth regulatory period in electricity
	Haslinger, Nagele (2018), *Kurzstellungnahme zu Fragen der Verfahrensrechte der WKÖ gemäß § 48 Abs 2 ElWOG 2010 in Verfahren zur Feststellung der Kostenbasis nach §§ 48 ff ElWOG 2010* (Short statement on the procedural rights of the Austrian Economic Chambers under section 48(2) Electricity Act 2010 in proceedings to determine the allowed cost pursuant to sections 48 et sqq. Electricity Act 2010)
4th high-level meeting, 11 June 2018	Oesterreichs Energie presentation: designing regulatory regime for future-proof electricity distribution system operation, fourth regulatory period

Expert meetings

1st expert meeting, 9 February 2018	Oesterreichs Energie presentation: industry views on benchmarking for the fourth regulatory period
	E-Control presentation: expert meeting on benchmarking for the fourth regulatory period in electricity
2nd expert meeting, 21 March 2018	E-Control presentation: expert meeting on benchmarking for the fourth regulatory period in electricity
	Oesterreichs Energie presentation: benchmarking adaptations
	Gugler K., Liebensteiner M. (2018a), *Empirische Schätzung des Produktivitätswachstums und Berechnung des generellen X-Faktors im österreichischen Stromverteilnetz* (Empirical estimate of the productivity rate and calculation of the general productivity rate for the Austrian electricity distribution network – study commissioned by Oesterreichs Energie)
3rd expert meeting, 27 April 2018	E-Control presentation: 3rd expert meeting on benchmarking for the fourth regulatory period in electricity
	RSA (2018), *Flächenanalyse für Benchmarking* (Area analyses for benchmarking), presentation on behalf of E-Control
	Consentec (2018), *Weiterentwicklung und Aktualisierung der trfNAD* (Developing and updating the transformed connection density), presentation on behalf of Oesterreichs Energie
	Oesterreichs Energie presentation: the smart metering operating cost factor
4th expert meeting, 8 May 2018	E-Control presentation: 4th expert meeting on benchmarking for the fourth regulatory period in electricity
	Oesterreichs Energie presentation: 5th expert meeting on benchmarking

	bpv HÜGEL (2018), *Memorandum – Sozialpartner und neue Regulierungsperiode* (Memorandum: the social partners and the next regulatory period), on behalf of Oesterreichs Energie
5th expert meeting, 6 June 2018	E-Control presentation: 5th expert meeting on benchmarking for the fourth regulatory period in electricity
	Swiss Economics (2018a), *Zwischenresultate Xgen* (Intermediate results on X-gen), on behalf of the Austrian Economic Chamber, 6 June 2018
	Frontier Economics (2018a), *Generelle Produktivitätsvorgabe* (General productivity rate), study commissioned by the Federal Chamber of Labour, 6 June 2018
	Gugler K., Liebensteiner M. (2018b), *Empirische Schätzung des Produktivitätswachstums im österreichischen Stromverteilnetz* (Empirical estimate of the productivity growth for the Austrian electricity distribution network), study commissioned by Oesterreichs Energie, 6 June 2018
	WIK-Consult (2018), *Ermittlung des generellen Faktorproduktivitätsfortschritts für Stromverteilernetzbetreiber in Österreich im Zuge der vierten Regulierungsperiode* (Calculating the general productivity growth for electricity Austrian distribution system operators during the fourth regulatory period), study commissioned by E-Control, 6 June 2018
	Frontier Economics (2018), *Effizienzabhängige Kapitalvergütung* (Individual WACC on RAB), study commissioned by the Federal Chamber of Labour, 6 June 2018
	Oesterreichs Energie presentation: designing regulatory regime for future-proof electricity distribution system operation, fourth regulatory period
	NERA (2018a), *WACC für Stromverteilnetze (2019-2023)* (Calculating the WACC for electricity distribution systems (2019-2023)), presentation of results, 6 June 2018
	BBH (2018a), *Zinsgutachten Strom für 4. Regulierungsperiode* (Study on cost of capital for the fourth regulatory period in electricity), summary of BBH results, 6 June 2018
	Consentec and Oesterreichs Energie (2018), *Branchenposition Benchmarking* (Industry views on benchmarking)
	Gugler K., Liebensteiner M. (2018c), *Stellungnahme zu den Präsentationen zum X-Gen Stromverteilnetz am 6.6.2018* (Reply to the presentations about the X-gen for the electricity distribution network held on 6 June 2018), study commissioned by Oesterreichs Energie, 19 June 2018
6th expert meeting, 25 June 2018	E-Control presentation: 6th expert meeting on benchmarking for the fourth regulatory period in electricity
7th expert meeting, 6 July 2018	Consentec (2018), *Benchmarkinganalysen mit Datenstand 2.7.2018* (Benchmarking analyses using data as of 2 July 2018), on behalf of Oesterreichs Energie, 6 July 2018
	E-Control presentation: 7th expert meeting on benchmarking for the fourth regulatory period in electricity
	Oesterreichs Energie (2018), *Wesentliche Kritikpunkte – aktualisierte TFP Berechnung ECA-WIK (25.6.18)* (Main issues – updated calculation of total factor productivity by E-Control and WIK of 25 June 2018)
8th expert meeting, 13 July 2018	E-Control presentation: 8th expert meeting on benchmarking for the fourth regulatory period in electricity – preliminary results of the process for information

19. Annex 3

Element in German equation	Explanation
ΔNPI_t	change in the network operator price index for year t
ΔTLI_t	change in the index of collectively agreed wages and salaries for year t
ΔVPI_t	change in the consumer price intext for year t
$\emptyset Effizienz$	average efficiency score
abhängige Variable	dependent variable
$Abschr.\ Rundsteueranlage$	depreciation of the ripple control system
AD, i	useful life for asset category i
AfA_{2017}	2017 depreciation
AHK_i^{ind}	indexed historical costs for asset category i
$Annuität_i$	annuity for asset category i
$Aufrollung_{2019}$	correction for the systemic time lag 2019
$Ausrollungsgrad\ in\ \%$	roll-out ratio in %
$beide\ Richtungen$	metering points with bidirectional meters
Beobachtungen	observations
$Betriebskostenfaktor_{2019}$	operating cost factor for 2019
$Betriebskostenfaktor\ Smart\ Metering$	smart metering operating cost factor
$BKFaktor_{2019}^{bish.Spezifikation}$	operating cost factor for 2019, calculated according to the specification that applied previously (3rd regulatory period)
$BKFaktor_t^{neue\ Spezifikation}$	operating cost factor for year t, calculated according to the new specification (4th regulatory period)
$CAPEX\ kalkulatorisch_j$	financial accounting CAPEX of a company j
$Doppeltarifzähler$	metering points with dual rate meters
$Effizienzwert_{4.Periode}$	efficiency score of the 4th regulatory period
$Effizienzwert_i$	efficiency score of company i
$Effizienzwert\_MOLS$	efficiency score out of MOLS
EK^{Anteil}	equity share
$Entnehmer\ inkl. unterbrechbare$	metering points for withdrawing parties, including interruptible metering points
ES_{2018}	individual efficiency score, evaluated 2018 with 2016 data
ESP_MW	injection capacity in MW
F Statistik	F statistic
FK^{Anteil}	debt share
FK^{Zins}	cost of debt
$genereller\ Normierungsfaktor$	general normalisation factor
$gewichtete\_reale\_Leitungslänge$	weighted real grid kilometres
Hinweis	note
$individueller\ Normierungsfaktor_j$	normalisation factor of a company j
$InvestFaktor_{2019}^{bish.Spezifikation}$	investment cost factor for 2019, calculated according to the specification that applied previously (3rd regulatory period)

$Einspeiser$	metering points for injecting parties
$Kapitalkostenabgleich_{2019}$	2019 direct CAPEX compensation
$Kapitalkostenabgl._{t}^{inkl.Mark-up}$	direct CAPEX compensation for year t, including the mark-up
$kTOTEX\ exkl.\ NV$	financial accounting TOTEX without costs for covering grid losses
$Messentgelte$	metering charges
$Messentgelte\ NE\ 6\ u.\ 7$	metering charges at network levels 6 and 7
nbK_t	non-controllable DSO costs in year t
Netzebene	network level
NHL_47	peak load at network levels 4 to 7
$normierte\ standardisierte\ CAPEX$	normalised standardised CAPEX
NPI	network operator price index
$OPEX_{2016}$	audited 2016 OPEX
$OPEX_{2019}^{Basis\ Entgelte}$	OPEX upon which the 2019 charges are based
$OPEX_{2018}^{Pfad}$	allowed 2018 OPEX
$OPEX\ abzgl.\ Bereinigungen$	OPEX minus corrections
$OPEX\ NE\ 6\ u.\ 7$	OPEX at network levels 6 and 7
$RAB_{Vermögen\ ab\ 2017}^{2017}$	2017 RAB made up of assets acquired from 2017
$RAB_{Vermögen\ bis\ 2016}^{2017}$	2017 RAB made up of assets acquired up to 2016
$Rendite^{EK}$	return on equity
$Residuum$	residual term
rZ	real interest rate
sTOTEX	standardised TOTEX
$Systemlänge\_HHSP_{2017}$	high- and extra-high-voltage grid kilometres in 2017
$Systemlänge\_Hochspannung$	high-voltage grid kilometres
$Systemlänge\_Höchstspannung$	extra-high-voltage grid kilometres
$Systemlänge\_MSP_{2017}$	medium-voltage grid kilometres in 2017
$Systemlänge\_NSP_{2017}$	low-voltage grid kilometres in 2017
TLI	index of collectively agreed wages and salaries
trfNAD_gesamt	aggregated transformed area-weighted connection density
trfNAD_HSP, MSP, NSP	transformed area-weighted connection density for high, medium and low voltage
$trfNAD_{HMNSP}$	transformed area-weighted connection density for low, medium and high voltage
$unterbrechbar$	interruptible metering points
Vollast_h_ZP	metering points weighted by full-load hours
VPI	consumer price index
$WACC_{überdurchschnittlich;i}^{Effizienz}$	individual WACC for a company i with an above-average efficiency score
$WACC_{unterdurchschnittlich;i}^{Effizienz}$	individual WACC for a company i with a below-average efficiency score
$WACC\_EFF$	individual WACC

$Xgen_{4.Periode}$	X-gen for the fourth regulatory period
$Zählpunkte_{2017}$	number of metering points in 2017
$Zählpunkte\_gesamt$	total number of metering points (network levels 3-7)
$Zählpunkte\ in\ beide\ Richtungen$	bidirectional metering points
ZP_gesamt	total number of metering points (network levels 6-7)
ZV	overall efficiency target
$ZV_{4.Periode}$	overall efficiency target for the fourth regulatory period