Council of European Energy Regulators

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CEER Report on Regulatory Frameworks for European Energy Networks 2020

Annex 5

Case studies of single regulatory regimes

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Annex 5.1 Case Study – Austria

The current document describes a short case study about the regulatory regime that applies to electricity distribution system operators in Austria during the fourth regulatory period and is based on the document Electricity Distribution System Operators 1 January 2019 – 31 December 2023 Regulatory Regime for the Fourth Regulatory Period (https://www.e-control.at/documents/1785851/1811597/Regulierungssystematik_4_Periode_STROM_Dez+2018_EN.pdf/75c38bb5-8903-7025-eb47-8bc72f4a7793?t=1562141191598). For further explanations, details and all references, please refer to this document.

Regulation of grid charges[1] can be based on annual cost audits, but this means significant 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. The Austrian national regulatory authority (NRA) prefers the latter approach as it minimises the direct costs of regulation. In between cost audits, operator costs and the derived grid charges 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.

When setting the length of a regulatory period, the regulatory authority must consider several effects. 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 is maintained for, i.e. it depends on the length of the regulatory period. 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. In Austria, both the regulatory authority and the regulated companies have gained extensive experience with incentive-based regulation. It therefore appears reasonable to maintain the 5-year period used previously.

With such a regime, cost data must be adjusted and corrected before they can be transformed into allowed costs and used in a 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 costs were reasonable in both their grounds and their amount.

The regulatory authority generally bases its assessment on the most recent available figures in its cost audits and in establishing the grid capacity and volumes the tariffs are based upon. However, the conducted cost audits require significant time and effort, both on the regulatory authority's end and on the companies'. Also, regulated companies must be given 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, the accounts of *all* companies that are being benchmarked must have been approved before the benchmarking can take place. For some grid operators, therefore, the regulatory authority must base its assessment on the second-to-last annual financial data available. For the fourth regulatory period which started in 2019, the regulatory authority therefore did not audit the costs of the most recent full business year (2017) but rather those of the previous year (2016).

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

Suppose that a specific distribution system operator's allowed cost base for 2016 amounts to €600,000 of OPEX and €100,000 of non-controllable costs. Assume that this operator's depreciation in 2018 is €100,000, the 2018 book value of its regulatory asset base until 2016 €1,000,000 and the 2018 book value of new investments from 2017 onwards €150,000.

The regulatory authority calculates the allowed **OPEX** by applying the network operator price index (NPI) and the general productivity growth rate (X-gen) of 0.95% p.a. 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.

$$\begin{aligned} Baseline\ OPEX\ 2018 &= 504{,}908 \\ &= (600{,}000 - 100{,}000) \times (1 + 1.614\%) \times (1 + 1.293\%) \times (1 - 0.95\%)^2 \end{aligned}$$ [2]

The allowed OPEX 2018 constitutes the baseline for the present regulatory period. In this context, the regulatory authority considers the company's overall efficiency target which is composed of the general productivity growth rate (X-gen) and the individual efficiency target (X-ind). This efficiency target (ZV) is directly derived from each company's efficiency score and a realisation period of 7.5 years. Therefore, the formula for each company's overall efficiency target is as follows:

$$\mathrm{ZV} = 1 - (1 - 0.95\%) \times \sqrt[7{,}5]{\mathrm{ES}_{2018}}$$

where ES_{2018} designates the individual (weighted) efficiency score. This efficiency score is derived from a benchmarking procedure that comprises two methods (DEA and MOLS), two TOTEX cost bases as inputs, a set of outputs derived from a cost driver analysis and an efficiency floor of 80%. An efficient company's overall efficiency target corresponds to the 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%

Table 1 – Efficiency scores and overal targets (Austria)

Assuming an efficiency score of 90%, the OPEX during the regulatory period are calculated as follows.

$$\begin{aligned} OPEX\ 2019 &= 501{,}857 = 504{,}908 \times (1 + 1.769\%) \times (1 - 2.332\%) \\ OPEX\ 2020 &= 501{,}501 = 501{,}857 \times (1 + 2.315\%) \times (1 - 2.332\%) \end{aligned}$$ [3]

Actual **non-controllable costs** enter the allowed costs without being subject to any efficiency targets.

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. The

[2] In English:
$Baseline\ OPEX_{2018}^{Allowed} = (OPEX_{2016} - NonControllableCosts_{2016}) \times \prod_{t=2017}^{2018}[(1 + \Delta NetworkOperatorPriceIndex_t) \times (1 - Xgen_{4thPeriod})]$

[3] In English:
$OPEX_t^{BasisForCharges} = OPEX_{t-1} \times (1 + \Delta NetworkOperatorPriceIndex_t) \times (1 - OverallEfficiencyTarget_{4thPeriod})$

regulatory authority introduced the concept of an individual WACC which it applied for assets acquired up to 2016; this individual WACC was designed to incentivise efficiency.

For this, the regulatory authority first calculates the average efficiency score across all companies, i.e. the arithmetic mean of all benchmarked system operators, and applies an efficiency floor of 80%. A company with an average efficiency score receives a nominal WACC of 4.88% (before taxation) on the regulatory asset base. If a company is more/less efficient than the average, its WACC is 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%, the regulatory authority offsets above-average and below-average efficiencies against each other.

Suppose that the average efficiency amounts to 92%. This leads to the following individual WACC for the focal grid operator.

$$4.80\% = 4.88\% - \frac{0.5\%}{(92\% - 80\%)} \times (92\% - 90\%)$$

The regulatory authority then applies 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 (minus customer prepayments) made in 2017 and 2018. This uniform rate was chosen because there was no annual efficiency benchmark, i.e. until the next benchmark is carried out and can be taken into account in future regulatory periods, the regulatory authority has to 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. Depreciation is passed through without any mark-downs or other changes, this system therefore minimises the risk exposure for system operators by guaranteeing that their investments are recovered through the grid charges.

Applying the individual WACC to the RAB and using the book values from year 2018 (see above), we arrive at the following calculation for the CAPEX to be included in 2020 grid charges:

$$CAPEX\ 2020 = 155{,}320 = 100{,}000 + 1{,}000{,}000 \times 4.80\% + 150{,}000 \times 4{,}88\%$$ [4]

Incentive regulation implies that the allowed costs are decoupled and may thereby diverge from actual costs. A new audit, based on which the allowed costs are determined anew, 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.) evolves during the course of a regulatory period, and the regulatory authority uses so-called expansion factors to account for such developments. This way, regulated companies can be sure that any increase in OPEX in line with the previously set parameters 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.

Using the most recent available data (financial accounting data and technical data) 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 2020 expansion factor and regulatory asset base rely on data from 2018 (see above), but it can be safely assumed that OPEX and CAPEX are not the same in 2020 as they were two years earlier. The same is true for the non-controllable costs. This systemic time lag could detain companies from investing because they only recover their costs two years later, when new investments are included as

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

part of direct CAPEX compensation and the parameters for the operating cost factor are updated. This means that companies would have to pre-finance these investments, meaning 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 result in rates that are too low for companies whose mandates are steadily growing or it could cause rates that are too high for customers of companies whose mandates are steadily shrinking. To protect both sides from these effects, the regulatory authority corrects for the difference between the t-2 data and the current data once these latter become available.

When calculating the system charges, the regulatory authority relies on the most recent available data on capacity and the volume transported. 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 the regulatory authority bases the 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. The system for cost regulation, therefore, includes a regulatory account where these differences are accounted for and recovered in the following cost decisions.

Annex 5.4 Case Study – Czech Republic

The following text offers an outline of the method for regulating revenues of gas distribution system operators (DSO) in the Czech Republic (the CR), including a description of the various parameters entering the calculations. Other gas and electricity system operators' revenues are regulated similarly, taking into account their respective specificities. The values shown in this case study are illustrative only; they are not based on any real values and only serve to provide for an easier understanding of the text in this document.

The revenue cap method is employed for regulating prices of the gas distribution system services in the Czech Republic; every year, the Energy Regulatory Office (the ERO) sets the value of allowed revenues for each of the regulated entities, which these entities are allowed to recover from their customers. In the price control process, these revenues are then allocated to the tariffs for each of the customer categories (customers are categorised by the annual gas quantity they take).

When setting the allowed revenues, the ERO proceeds in line with the document *Price Control Principles for the Electricity and Gas Industries and for the Market Operator's Activities in the Electricity and Gas Industries for 2016-2018*, *the effect of which has been extended to 31 December 2020*[5]. Under the Energy Act,[6] the price control principles are issued at least for five years (the fourth regulatory period (4RP) is 2016-2020). The ERO is currently drafting the price control principles for 2021-2025; they will also be published in a manner allowing remote access.

The following formula is employed for calculating the gas DSOs' allowed revenues (**AR**):

$$\mathbf{AR = AC + AD + P + MF + CoL + CF}$$

The terms of this equation are described in the following:

Allowed costs (AC)

Allowed costs are included in regulated entities' regulated prices. The price regulation process does not examine the actual costs spent by each of the companies on ensuring the operation of distribution systems in each of the years; it uses the actual costs of selected reference years (for the 4RP, the years 2012 and 2013 are used, and they form 'the cost base'), which are only escalated to the value of the relevant regulated year. The escalation index is composed of two indices published by the Czech Statistical Office, specifically the producers price index (PPI) with a weight of 70% and the consumer price index (CPI), increased by a bonus of 1%, with a weight of 30%. When determining the allowed costs for each of the years of the 4RP, the ERO also takes into account the efficiency factor, which has been set at 1.01% for all years of the 4RP. The purpose of the efficiency factor is to simulate the effect of market forces in the regulated sector, as it reflects productivity growth throughout the sector. Thanks to an approach relying on the cost base and the use of the escalation factor and the efficiency factor, achieving cost savings is highly motivational for the regulated entities because the entire savings will be felt in the company's bottom line. The approach is also beneficial for customers because for the future regulatory periods, the cost base is calculated precisely from the values of the years in which the companies were motivated to the maximum efficiency of their operation.

5 http://www.eru.cz/documents/10540/3550177/Zasady-cenove-regulace-IV-RO-prodlouzene-do-2020.pdf (available only in Czech).
6 Act No 458/2000 on Conditions for Business and State Administration in Energy Industries and Amending Certain Laws (the Energy Act).

The table below shows the values of the cost base for the 4RP, the development of allowed costs, the escalation (including the efficiency factor), actual costs, and cost savings as the difference between planned and actual costs.

Allowed costs	4RP	2016	2017	2018
Cost base for the 4RP	**1,245**			
Escalation (including the efficiency factor)		99.4%	99.4%	100.1%
Allowed costs		**1,238**	**1,230**	**1,231**
Actual costs		**1,193**	**1,196**	**1,230**
Difference		45	34	1

Table 2 – Allowed costs in the 4RP (Czech Republic)

Allowed depreciation (AD)

The total value of allowed depreciation is derived from the value of the assets that the regulated entities use for pursuing their licensed activities. Regulated companies must have assets that will help them to ensure safe, reliable, and economical operation, maintenance, and replacement, i.e. the duties laid down in the Energy Act. Regulated companies' assets are depreciated on a straight-line basis. In its public notice[7] the ERO sets out the annual depreciation rates for each asset category[8]. Depreciation is set as a planned value and following the end of a regulated year this value is compared with the actual value. The difference is then reflected in the value of the allowed depreciation for the nearest possible period.

The following table shows the development of allowed and actual depreciation in 2016-2018.

Depreciation	2016	2017	2018
Allowed depreciation	**1,187**	**1,063**	**1,166**
Actual depreciation	**1,263**	**1,088**	**1,084**
Difference	-75	-24	82

Table 3 – Allowed depreciation in the 4RP (Czech Republic)

Profit (P)

Companies' profit is also derived from the value of their assets (or, more precisely, the value of the Regulatory Asset Base, RAB). At the beginning of the 4RP, the initial value of the Regulatory Asset Base was determined; in each of the years this value is augmented by the planned investments and reduced by the planned depreciation. The RAB so calculated is the basis for calculating profit every year. The return on assets is calculated as the weighted average cost of capital, WACC, which does not change throughout the regulatory period and is 7.94% (nominal, pre-tax). The ERO used the following formula for calculating WACC:

$$WACC=\left(k_e \times \frac{E}{D+E}\right)+\left[\left(k_d \times \frac{D}{D+E}\right)\times(1-T)\right],$$

where

$\mathbf{k_e}$	cost of equity	$\frac{E}{D+E}$	share of equity
$\mathbf{k_d}$	cost of debt	$\frac{D}{D+E}$	share of debt
T	corporate tax rate		

Companies' profit is then the product of RAB times WACC. Since the value of profit is derived from the planned RAB value, the planned and actual values of RAB are compared in retrospect (on the basis of actual investments and actual depreciation), as in the case of

[7] Public notice 262/2015 on Regulatory Reporting.
[8] The main assets: Pipelines 2.5%; Compressors 5%; Metering 10%.

depreciation. The difference in profit, resulting from the comparison of the planned and actual values of RAB, is then reflected in the value of the planned profit for the nearest possible period.

The following table shows the planned and actual values of profit and the difference between them in 2016-2018.

Profit	2016	2017	2018
Allowed profit	**1,084**	**1,114**	**1,134**
Actual profit	**1,074**	**1,119**	**1,130**
Difference	10	-5	4

Table 4 – Allowed profit in the 4RP (Czech Republic)

Market Factor (MF)
The market factor is used in cases where regulated entities incur costs that are not demonstrably contained in the set cost base and that result from changes in the legislation, the development of the market situation, the implementation of new technologies, or the disposal/retirement of large assets. Regulated companies request the acknowledgement of the costs actually spent on the above developments. The ERO examines these requests *inter alia* from the perspective of the economic justifiability of each of the requirements received. Where the ERO approves this, such costs are factored in the allowed revenues for the next subsequent year. During the 4RP to date, this procedure has been used very rarely in the case of gas DSOs.

Cost of Losses (CoL)
For the 4RP, these costs were determined as the product of the allowed gas quantity for covering losses and the annual unit maximum price of gas supply for losses. A single value of the allowed quantity of losses was determined for the whole regulatory period, at the level of the arithmetic mean of the actually registered values of losses between 2008 and 2012. The maximum unit price of gas supply for losses is derived from the gas price at exchanges. The planned and actual costs of losses are not compared, and for the regulated companies achieving savings in this area is motivational because these savings are fully reflected in the companies' bottom line.

The following table shows allowed and actual costs of losses and the difference between them from 2016 to 2018.

Cost of losses	2016	2017	2018
Allowed cost of losses	**264**	**203**	**196**
Actual cost of losses	**137**	**98**	**121**
Difference	127	105	75

Table 5 – Allowed cost of losses in the 4RP (Czech Republic)

Correction Factor (CF)
Since the value of actual revenue depends on the actual booked capacities and the gas quantity actually taken by customers, following the end of the year the values of the allowed and actual revenue from the provision of the distribution system services are compared. The difference (the correction factor) resulting from this comparison is then reflected in calculating allowed revenue for the nearest possible period. Regulated entities therefore enjoy the certainty that in case of being unsuccessful in recovering revenue in a particular year due to a smaller gas quantity taken by customers, or lower than expected booked capacities, the revenue portions not recovered are moved to the prices for the next subsequent period. By the same token, customers enjoy the certainty that in case of paying towards higher revenue

than set for the regulated entities, the prices in the next subsequent period will be reduced by this revenue portion.

Allowed Revenue (AR)
The value of allowed revenue is calculated using the above formula. The table below shows the development of the values of allowed revenue, the values of actually recovered revenue, and the revenue correction factor, resulting from these values, in each of the years of the 4RP to date.

Revenue	2016	2017	2018
Allowed revenue	**3,773**	**3,610**	**3,727**
Actual revenue	**3,543**	**3,642**	**3,808**
Correction factor (CF)	-230	32	81

Table 6 – Allowed revenue in the 4RP (Czech Republic)

Distribution bands of consumption
On the basis of the planned booked capacities and the planned quantity taken, allowed revenue is specified in tariffs for each of the customer categories for the purpose of regulating the prices for the distribution system services.

In the Czech Republic, all customers are included in categories (referred to as ‘consumption bands’) based on the gas quantity they take.

<u>Consumption bands in the CR:</u>

- Large-demand and medium-demand customers (over 630 MWh/yr) connected to long-distance gas pipelines (operating pressure over 0.4 MPa)

- Large-demand and medium-demand customers (over 630 MWh/yr) connected to local networks (operating pressure up to 0.4 MPa)

- Low-demand and household customers: 63–630 MWh/yr
  45–63 MWh/yr
  25–45 MWh/yr
  15–25 MWh/yr
  7.56–15 MWh/yr
  1.89–7.56 MWh/yr
  0–1.89 MWh/yr

Annex 5.7 Case Study – Finland

This section describes a simplified case study about the regulatory regime and methodology for setting allowed revenues for electricity distribution system operators in Finland for the fifth regulatory period 2020 – 2023. The regulatory framework and principles applied are explained in more detail in the regulation methods document[9] which can be found in the Energy Authority's webpage. The Energy Authority (the Finnish NRA) applies slightly divergent methodologies when setting the revenue cap for transmission system operators and distribution operators in the natural gas sector and the electricity sector, however the main principles are the same.

The regulatory framework is twofold, on one hand the capital committed to the network operations is reviewed and reasonable return calculated on it and on the other hand, the adjusted operating profit of network operations is reviewed.

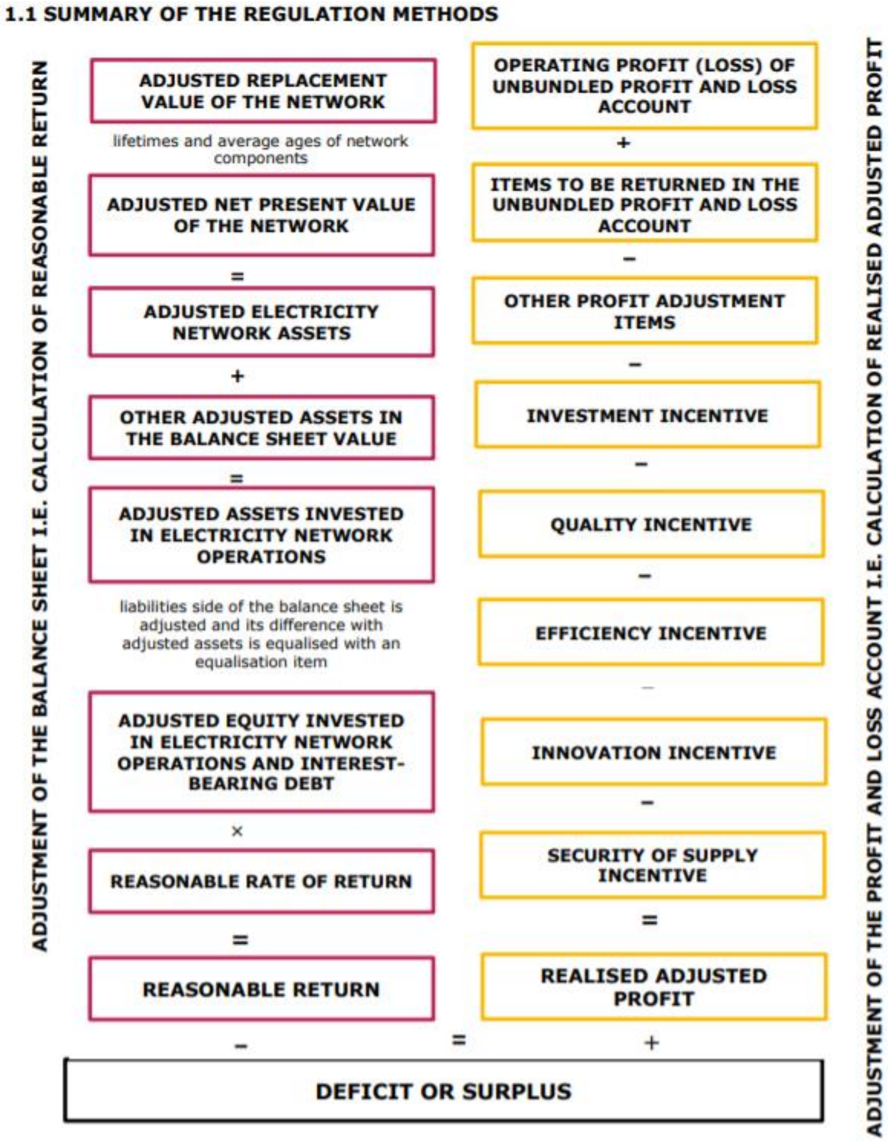

Figure 1 – Regulation methods during regulatory periods 2016-2019 and 2020-2023 (Finland)

[9]https://energiavirasto.fi/documents/11120570/13078331/Appendix_2_Regulation_methods_DSOs_2016-2023.pdf/0c4db75e-826a-8ca6-c749-1e69fa37a5e3/Appendix_2_Regulation_methods_DSOs_2016-2023.pdf

Adjustment of the balance sheet i.e. calculation of reasonable return
Adjustment of the balance sheet is the base in the calculation of reasonable return, i.e. the revenue cap. The Energy Authority determines annually a reasonable return for each DSO, which in turn is dependent on the adjusted assets and capital invested in network operations.

The electricity network forms the greatest individual part of the DSO's assets, i.e. the non-current assets in the unbundled balance sheet. The electricity network value according to the balance sheet is not, however, used when determining the revenue cap, as the value of the network assets are adjusted to correspond with their actual net present value. Hence, the revenue cap is calculated to the adjusted net present value of the network which is determined from the adjusted replacement value of the network.

The adjusted replacement value of the network is obtained by adding together all the network components and they are multiplied with component-specific unit prices (according to a pre-determined unit price catalogue). In turn, the adjusted net present value of the network is calculated from the adjusted replacement values of the components by taking into account the lifetime and average age of the components.

The adjustment of capital invested in network operations is based on the liabilities side of the DSO's unbundled balance sheet. The adjusted capital invested consists of the adjusted equity, adjusted interest-bearing debt and adjusted non-interest-bearing-debt. An equalisation item is also added to this in order to balance the assets and liabilities in the adjusted balance sheet and it is recorded under equity.

The DSO's revenue cap is calculated by multiplying the adjusted capital invested in the electricity network by the reasonable rate of return (WACC-%). The DSO receives reasonable return on adjusted equity and interest-bearing debt, as there is no return obtained for non-interest-bearing debt.

Adjustment of the profit and loss account
Adjustment of the profit and loss account is made to determine the DSO's realised adjusted profit. The calculation of realised adjusted profit begins from the operating profit (loss) from the DSO's unbundled profit and loss account. In the calculation of the realised adjusted profit, certain items are returned to the operating profit, of which the most significant is planned depreciation in the unbundled profit and loss account. After the returnable items have been added to the operating profit, reasonable cost of financial assets is deducted as profit adjustment items. Also, the impact of incentives is deducted from the operating profit. Incentives included in the regulation methods for electricity DSOs are the investment incentive, quality incentive, efficiency incentive, innovation incentive and security of supply incentive. The sum total of the calculation is the realised adjusted profit.

Surplus or deficit of the financial period
Finally, the deficit or surplus of the return for the corresponding year is obtained by deducting the reasonable return from the realised adjusted profit, positive value from the subtraction meaning surplus and negative meaning deficit.

At the end of regulatory period, the DSO's realised adjusted profits from different years are added together and deducted from the sum of reasonable returns from the corresponding years. Surplus will be compensated back to customers with lower distribution tariffs in the next regulatory period. If the realised adjusted profit during the regulatory period has exceeded the amount of reasonable return by at least 5%, interest shall be payable on the surplus. The interest rate is the average of the reasonable cost of equity for the years of the regulatory period in question.

Incentive mechanism

Investment incentive
The investment incentive is designed to guide DSOs to make investments cost-effectively. The incentive impact is based on the network components' unit prices and the straight-line depreciation calculated from the adjusted replacement value. Basically, if the DSO is able to implement network investments with lower costs than the unit prices suggest, the DSO will benefit from the difference on the straight-line depreciations calculated from the asset's or assets' adjusted replacement value and the planned depreciation calculated from the asset's or assets' balance sheet value. In addition, the DSO will get a higher value for its investments than the actual investments as the reasonable return on network assets is calculated based on the adjusted replacement value.

Quality incentive
The quality incentive directs DSOs to develop the quality of distribution and to minimise the number and duration of electricity distribution outages. The incentive is based on so-called regulatory outage costs, i.e. the disadvantage caused to the end user by the outage. Outage costs are calculated on the basis of the number and duration of outages as well as the pre-determined unit prices of outages which are based on a study commissioned by the Energy Authority.

In the fifth regulatory period (2020 – 2023), the number and duration of planned and unexpected outages, the number of high-speed autoreclosers and the number of time-delayed autoreclosers are taken into account from medium-voltage and high-voltage distribution networks when determining the outage costs. The DSO's average realised regulatory outage costs for two previous regulatory periods (2012 – 2019), are used as the reference level of regulatory outage costs. The impact of the quality incentive is calculated so that the realised regulatory outage costs are deducted from the reference level of regulatory outage costs.

The impact of the quality incentive is deducted in the calculation of realised adjusted profit. The effect of the incentive (bonus or sanction) is limited to 15% of the DSO's reasonable return for the year in question.

Efficiency incentive
The efficiency incentive guides DSOs to operate in cost-effective manner and the incentive is targeted to the controllable operational costs. The incentive steers DSOs to effective day-to-day operations and encourages them to invest in a way which will lower the operational costs.

The incentive is based on the DSO's reasonable controllable operational costs are which are used as a reference level in the assessment of the DSO's effectiveness. The reference level describes the cost level at which an efficient DSO can perform operational functions with high-quality and cost-effectively while taking into account the DSO's output level and operating environment. The DSO-specific reference levels are derived from the estimated efficiency frontier using a benchmarking procedure (StoNED-method) based on regulatory data collected from DSOs. The variables in the efficiency frontier estimation and derivation of DSO-specific efficiency consist of input variables (controllable operational costs and replacement value of the network), output variables (volume of transmitted energy, total length of the network, number of metering points and regulatory outage costs) and an operating environment variable (the ratio of the number of connections and metering points).

The impact of the efficiency incentive is calculated by deducting the DSO's realised controllable operational costs from the reference level of efficiency costs for the year in question. The Energy Authority applied in the fourth regulatory period (2015 – 2019) a transition period for the improvement of efficiency, during which the DSOs must reach an efficient cost level. However, in the fifth regulatory period (2020 – 2023), there is no more transition period left and the DSO's realised controllable operational costs are compared directly with the level of efficient operational costs in accordance with the efficiency frontier.

The effect of the incentive (bonus or sanction) is limited to 20% of the DSO's reasonable return for the year in question and impact of incentive is deducted in the calculation of realised adjusted profit.

Innovation incentive
The purpose of the innovation incentive is to encourage the DSO to develop and use innovative technical and operational solutions in its network operations. The DSO's efforts in research and development are rewarded by deducting reasonable R&D expenditure in the calculation of adjusted profit. Acceptable R&D costs must be directly related to the creation of new knowledge, technology, products or methods of operation in network operations for the sector. The results of the projects must be publicly available to be accepted for this incentive.

The impact of the innovation incentive is calculated so that a share corresponding to a maximum of 1% of the DSO's total turnover from network operations in the unbundled profit and loss accounts in the regulatory period are treated as reasonable research and development costs. The impact of the incentive is deducted when calculating realised adjusted profit.

The security of supply incentive
The security of supply incentive was introduced to regulatory methods for the fourth (2016 – 2019) and fifth (2020 – 2023) regulatory periods as a consequence of large-scale storms especially in the early 2010s, resulting in hundreds of thousands of people without electricity for significant periods of time. According to the Electricity market act (588/2013), after 2028 there shall not be interruptions in electricity delivery due to the weather conditions longer than six hours in town-planned areas, or 36 hours in rural areas. Due to these requirements, there are gradual requirements for DSOs to build weatherproof network coverage. The purpose of the security of supply incentive is to enable DSOs to meet the security of supply criteria required by the law within the deadline as cost-effectively as possible in view of the achieved benefits.

The security of supply incentive consists of two entities, the write-downs of net present value of the network caused by premature replacement investments and reasonable costs of new maintenance and preventive measures.

The impact of the security of supply incentive is calculated by adding together the write-downs of the net present residual values resulting from early replacement investments carried out in order to improve security of supply and the reasonable costs of maintenance and contingency measures. The impact of the security of supply incentive is deducted when calculating realised adjusted profit.

Application example:
The following presents a simplified example of the application of the regulatory framework in Finland and how the allowed revenue is determined for two fictious electricity distribution system operators. When determining the revenue cap, we start off with the adjusted balance sheet. All the figures presented in the tables are in thousands of euros.

ADJUSTED BALANCE SHEET	DSO A	DSO B
ASSETS		
Adjusted non-current assets		
Net present value of the network	100,000	100,000
Adjusted current assets	0	0
Adjusted balance sheet total	**100,000**	**100,000**
LIABILITIES		
Adjusted equity		
Equity in the balance sheet value	6,000	5,000
Equalisation item of adjusted balance sheet	54,000	75,000
Adjusted debt		
Interest-bearing	10,000	0
Non-interest-bearing	30,000	20,000
Adjusted balance sheet total	**100,000**	**100,000**

Table 7 – Example of the application of the regulatory framework (Finland)

We can see that DSO A and DSO B have the same size of adjusted electricity network assets, totalling to €100 million (M). However, the DSOs have a different financial structure as DSO A has €60 M of equity, €10 M of interest-bearing debt and €30 M of non-interest-bearing debt while DSO B has €80 M of equity and €20 M of non-interest-bearing debt.

The reasonable return i.e. revenue cap is calculated by multiplying the adjusted capital invested in network by the reasonable rate of return (WACC-%). We need to determine the applicable WACC-% which consists of the reasonable cost of equity, reasonable cost of debt and assumed optimal capital structure. In the determination of the reasonable rate of return we shall use the parameter values which the Energy Authority applies in 2020.

PARAMETER	VALUE (2020)
Risk-free rate (R_r)	1.45%
Equity beta (β_{equity})	0.828
Market risk premium ($R_m – R_r$)	5.0%
Premium for lack of liquidity (*LP*)	0.6%
Debt premium (*DP*)	1.26%
Gearing	40%
Equity	60%
Rate of Corporate tax (*yvk*)	20%

Table 8 – Parameters (Finland)

Where
Reasonable cost of equity;
CE = Rr + βequity × (Rm – Rr) + LP
CE = 1.45% + 0.828 × 5.0% +0.6% = 6.19%
Reasonable cost of debt;
CD = Rr + DP
CD = 1.45% + 1.26% = 2.71%
Reasonable rate of return;

$$WACC_{pre-tax} = \frac{C_E \times 0.60}{(1 - yvk)} + C_D \times 0.40$$

$$WACC_{pre-tax} = \frac{6.19\ \% \ \times\ 0.60}{(1 - 20\ \%)} + 2.17\ \% \times 0.40 = 5.73\ \%$$

Now when the reasonable rate of return is determined we can calculate the revenue cap for the DSOs.

REASONABLE RETURN	DSO A	DSO B
Adjusted equity	60,000	80,000
Interest-bearing debt	10,000	0
WACC-%	**5.73%**	**5.73%**
Reasonable return	**4,009**	**4,581**

Table 9 – Reasonable return (Finland)

As the there is no return obtained for non-interest-bearing debt, the reasonable return is calculated by adding together adjusted equity and interest-bearing debt and multiplied with reasonable rate of return.

DSO A: 5.73 % × (€60,000 thousand (t) + €10,000 t) = **€4,011 t**
DSO B: 5.73 % × (€80,000 t+ €0 t) = **€4,581 t**

Now as the reasonable return is determined for both DSOs, the profit and loss accounts need to be adjusted to determine the realised adjusted profit. This is done by adding the refundable items and deducting reasonable cost of financial assets and the effect of incentives from the DSOs' operating profit (loss).

ADJUSTED PROFIT AND LOSS ACCOUNT	DSO A	DSO B
Operating profit (loss)	6,500	7,000
Items returned into the operating profit (loss)		
Planned depreciations and value reductions from network assets	+ 4,500	+ 4,000
Other profit adjustment items		
Reasonable costs of financial assets	- 100	- 70
INVESTMENT INCENTIVE		
Adjusted straight-line depreciation of the electricity network assets	- 5,000	- 5,000
QUALITY INCENTIVE		
Realised regulatory outage costs	500	500
The reference level of regulatory outage costs	1,500	1,000
Effect of the Quality Incentive	- 602	- 500
EFFICIENCY INCENTIVE		
Realised controllable operational costs (KOPEX)	6,000	3,000
Reasonable controllable operational costs (SKOPEX)	5,500	4,000
Effect of Efficiency Incentive	+ 500	- 916
INNOVATION INCENTIVE		
Reasonable costs of research and development activities	- 50	0
THE SECURITY OF SUPPLY INCENTIVE		
Write-downs of NPV residual value from early replacement investments	- 300	- 300
Reasonable costs of maintenance and contingency measures	- 200	0
Realised adjusted profit	**5,248**	**4,214**

Table 10 – Adjusted profit and loss account (Finland)

Firstly, let us assume that DSO A has operating profit of €6,500 t and DSO B €7,000 t calculated from the unbundled profit and loss account. To the operating profit is returned planned depreciations and value reductions of electricity network assets in non-current assets, for DSO A €4,500 t and for DSO B €4,000 t. After this the reasonable costs of financial assets are deducted from the operating profit, for DSO A €100 t and DSO B €70 t. Finally, we deduct the impact of incentives from the operating profit to get the realised adjusted profit.

Effect of Investment incentive
Both DSOs have made the network investments with 20-year depreciation period and calculated with standard unit prices the value of network assets is €100 M for both DSOs. Let us assume that in reality DSO A paid €95 M for the network assets but DSO A has invested more efficiently and paid only €80 M for the assets. As the planned depreciations from 20-year depreciation period, calculated according to the unbundled balance sheet, was returned to the adjusted profit earlier, €4 500 t for DSO A and €4 000 t for DSO B. Now from the effect of investment incentive the straight-line depreciation calculated according to the standard unit prices, €5,000 t for both DSOs, is deducted from the adjusted profit. Thus, DSO A's decreased by €500 t and DSO B's by €1,000 t. Additionally, DSO A's regulatory asset value increased by €5 M and DSO B's by €20 M.

Effect of Quality incentive
Let us assume that DSO A's reference level of regulatory outage costs is €1,500 t and DSO B's is €1,000 t. The realised regulatory outage costs for both DSO's are €500 t and therefore below the reference levels. The impact of quality incentive is calculated by deducting the reference level of outage costs from the realised regulatory outage costs. For DSO A the effect of quality incentive, €500 t - €1,500 t = -€1,000 t, exceeds the 15% threshold level and in this case DSO's quality bonus is limited to the 15% from the reasonable return, -15% × 4,011 t€ = -€602 t. For DSO B the threshold is not exceeded so the effect of quality incentive is €1,000 t - €1,500 t = -€500 t.

Effect of Efficiency incentive
Assuming that DSO A's reasonable operational costs as a result of a national efficiency benchmarking (efficiency frontier) is €5,500 t and DSO A's realised controllable operational costs are €6,000 t. DSO A has inefficiencies in its operations as its realised controllable OPEX is above the efficient reference cost level. The impact of the efficiency incentive is calculated by deducting the efficient reference cost level from the DSO's realised controllable OPEX, €6,000 t - €5,500 t = €500 t. This efficiency sanction resulting from increased costs is added to the realised adjusted profit.

DSO B's reasonable controllable operational costs according to efficient operations is €4,000 t and realised controllable OPEX is assumed to be €3,000 M. We can see that DSO B has operated super-efficiently as its realised controllable OPEX is below its efficient cost level. As the efficient reference costs are deducted from the realised controllable OPEX, incentive effect is €3,000 t - €4,000 t = -€1,000 t. As DSO B's reasonable return was set to €4,581 t, the calculated impact of the efficiency incentive exceeds the 20% threshold level set to the incentive. In this case DSO's efficiency bonus is limited to the 20% from the reasonable return, -20% × €4,581 t = -€916 t. The efficiency bonus is deducted from the realised adjusted profit.

Effect of Innovation incentive
Let us assume that DSO A has developed an Internet of Things-project that can be used to proactively identify the repair needs for substations and thus initiate corrective action more quickly. The project enables cost-effective monitoring and ultimately reduces repair and maintenance costs. DSO A has published the results of the project and the Energy Authority has approved the costs of the project for the innovation incentive. DSO A has used € 50 t for

the project which will be deducted from the realised adjusted profit. DSO B has not published any research relating to the electricity network sector and therefore is not entitled to an innovation incentive bonus.

Effect of the security of supply incentive
DSO A has made acceptable write-downs of net present value residual value from early replacement investments worth of €300 t and reasonable costs of maintenance and contingency measures worth of €200 t, the effect of incentive totalling €500 t. DSO B has made acceptable write-downs of net present value residual value from early replacement investments worth of €300 t but no maintenance measures when the effect of incentive is €300 t. The effect of the security of supply incentive is deducted from the operating profit.

Now when all the effects of incentives have been calculated we can determine the realised adjusted profit for both DSOs.

DSO A: €6,500 t + €4,500 t – €100 t – €5,000 t – €602 t + €500 t – €50 t – €500 t = **€5 248 t**
DSO B: €7,000 t + €4,000 t – €70 t – €5,000 t – €500t – €916 t – €300 t = **€4,214 t**
Finally, we can calculate the surplus or deficit of the corresponding year for both DSOs by deducting the reasonable return from the realised adjusted profit.

Surplus / deficit of the financial period	**DSO A**	**DSO B**
Realised adjusted profit	5,248	4,214
Reasonable return	4,009	4,581
Surplus (+) / deficit (-)	**1,239**	**- 367**

Table 11 – Surplus/deficit of the financial period (Finland)

We can see that DSO A's return is in surplus and DSO B's return is in deficit. At the end of regulatory period the DSOs' realised adjusted profits from different years are added together and deducted from the sum of reasonable returns from the corresponding years. If the DSO has cumulative surplus transferring to the next period it must be equalised during the next regulatory period by lowering distribution tariffs. If the DSO in turn has cumulative deficit transferring to the next period the DSO can equalise it during next period with higher tariffs.

Annex 5.9 Case Study – Germany

Determination of the revenue cap of a German electricity distribution system operator.

Introduction

The electricity and gas network operators in Germany at transmission and distribution network levels are identified as natural monopolies. As such they are subject to government regulation. The German regulatory system provides incentive regulation through the setting of revenue caps. For the duration of one regulatory period, a revenue cap is prescribed for the network operators ex-ante for each year. Based on these revenue caps and the forecasted volumes of energy supplied, the network operators then determine the network tariffs that they levy on the energy suppliers. The energy suppliers themselves pass on these network tariffs directly to the final consumers by incorporating the network tariffs into the energy sales price in the form of a fixed value.

This case study focuses on the determination of the revenue cap in general and its individual components. This description is intended to facilitate a better understanding of sub-chapter 2.9 of the 2020 Regulatory Frameworks Report (RFR). As the sub-chapter is limited to a maximum of five pages, this case study serves to illustrate the application of the regulatory system. For this purpose, diagrams will be added and elucidated as needed. Finally, the determination of the revenue cap will be illustrated based on a virtual comparison of two electricity distribution system operators. Depending on the design of the framework conditions, subsequent versions could also include a comparison between individual countries taking part in the RFR.

The determination of the revenue cap

For the determination of the revenue cap, the DSOs in principle apply the following formula:

$$RC_t = C_{pnc,t} + (C_{tnc,t} + (1 - D_t) * C_{c,t} + \frac{B_0}{T}) * (\frac{CPI_t}{CPI_0} - PF_t) + CM_t + Q_t + (VC_t - VC_0) + A_t$$

The main component of the formula and thus of the revenue cap (RC) is the sum of the permanently non-controllable costs (C_{pnc}) as well as the (temporarily non-) controllable costs (C_{tnc} and C_c), which in turn are influenced by the consumer price index (CPI) as well as the productivity factor (PF), and which can, if applicable, be expanded by an efficiency bonus (B_0), divided into equal parts for each year of the five(T)-year regulatory period. Controllable costs (C_C) are distributed across the individual years of a regulatory period using a distribution parameter (D). This formula is supplemented by individual components from the capital cost mark-up (CM), the quality element (Q), the volatile costs (VC) as well as the balance (A) of the individual regulatory account.

The costs incurred in the base year are requested from the network operators and reviewed. First, the permanently non-controllable costs are deducted from the reviewed overall costs. These costs are set by way of existing definitions and can be directly transferred to the revenues. These include, for example, additional non-wage staff costs, concession fees or, for TSOs, approved investment measures for investments in expansion and restructuring.

The remaining cost block is composed of current outlay costs (e.g. expenditures for material and personnel), imputed depreciations (longer depreciation periods than in the German Commercial Code), imputed returns on equity as well as imputed trade tax, minus cost-reducing revenues.

The efficiency scores determined in a national TOTEX[10]-efficiency benchmarking are then applied to this cost block. The identified proportion of inefficiencies is applied to the remaining cost block, thereby forming the controllable costs. Deducting the controllable costs from the previously remaining cost block produces the temporarily non-controllable costs.

Additionally, the reduction of capital costs (based on depreciation and lower interest amounts) is deducted from both the temporarily non-controllable costs and the controllable costs.

Since the inefficiencies are to be removed uniformly over the course of one regulatory period, each year an increasing reduction factor ($1\text{-}D_t$) is applied to the controllable costs. This gives the revenue cap a stepped trajectory, as illustrated in Figure 2:

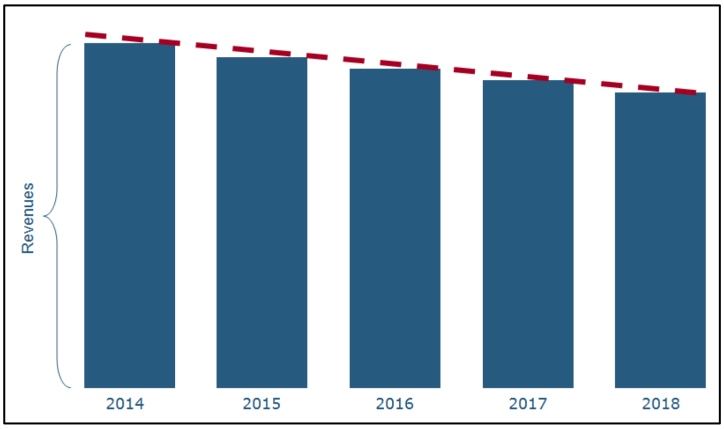

Figure 2 – Revenue cap as stepped trajectory (Germany)

Due to the existing budgetary principle the network operators have to decide where to reduce the inefficiencies. Neither the cost review nor the efficiency benchmarking identifies concrete inefficient cost positions, only inefficiencies in general.

In addition to the deduction of the reduced capital costs, the determined temporarily non-controllable and controllable costs from the base year are applied to the entire regulatory period; this is precisely where the incentive lies for network operators to reduce costs. The set revenue cap enables additional profits to be made through cost reductions within the regulatory period, as Figure 3 illustrates:

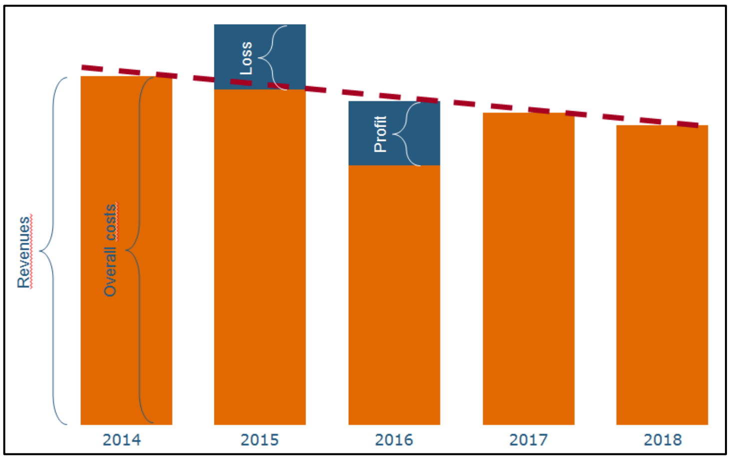

Figure 3 – Revenue cap enables additional profits (Germany)

[10] TOTEX = Total expenditures = Sum of operational costs (OPEX) and capital costs (CAPEX).

If within the framework of an outlier analysis a DSO is determined to be super-efficient (efficiency score > 100%), that DSO receives a certain efficiency bonus (limited to 5%) on the revenues, uniformly distributed over the duration of the regulatory period.

The development of consumer prices as well as the productivity of the network operators is taken into account through a correction factor on the temporarily non-controllable costs, on the controllable costs and, if relevant, on an efficiency bonus.

The revenue cap is also supplemented by mark-ups for additional planned capital costs, as well as by amounts for quality regulation, for changes in the so-called volatile costs and for the annual balance of the individual regulation account.

For a capital cost mark-up, network operators report in the previous year on the amount of their planned investments in necessary network assets. These capital costs are made up of the imputed depreciations, the imputed return on equity, the imputed trade tax as well as the incurred interest on debt.

The quality regulation calculates a positive or negative amount, depending on the existing quality of security of supply.

Volatile costs are costs incurred in the technical operation of the grids, for example driving energy or flow commitments.

Deviations between amounts or cost values estimated ex-ante and identified ex-post are booked onto a regulatory account that exists for each network operator. The balance of the regulatory account is also factored into the revenue caps.

Application example:
A simplified example of the application of the German regulatory system to calculate revenue caps/network tariffs is given below using two electricity distribution system operators. The framework/market conditions are shown in the following table:

Framework conditions (base year´s situation):

	DSO A	**DSO B**
Staff costs	1,000	800
Material costs	500	200
Operating taxes	50	30
∑ OPEX	1,550	1,030
Depreciations[11]	900	870
Interest rate on equity	6.91%	6.91%
Return on equity	100	50
Cost of debt	50	40
∑ CAPEX	1,050	960
∑TOTEX (OPEX + CAPEX)	2,600	1,990
Other revenues	-100	-50
Trade taxes	50	60
Consumer price index in the base year	100	100

Table 12 – Framework conditions (Germany)

[11] Based on calculated costs instead of depreciations defined by German Commercial Code.

For each DSO (here A and B) the revenue cap is calculated by summing up the single calculated components of the revenue formula. To this end, we take the following steps for each DSO individually:

1. Review of overall costs and the different cost categories
2. Application of the efficiency score
3. Determination of other revenue components
4. Final calculation of the revenue cap

Step 1: Review of overall costs and the different cost categories

To calculate the reviewed overall costs, we add the DSO's material and labour costs, depreciations, return on equity, trade tax and subtract the cost-reducing revenues from this amount. After that we have the overall DSO's overall cost, which we reduce by the amount of pre-determined permanently non-controllable costs.

	DSO A	DSO B
1. Material and staff costs (∑)	1,500	1,000
2. Operating taxes	50	30
3. Depreciation	900	870
4. Return on equity[12]	100	50
5. Cost of debt	50	40
6. Trade taxes	50	60
7. Other revenues	-100	-50
8. Reviewed overall costs (∑ 1. - 7.)	2,650	2,000
9. Permanently non-controllable costs[13]	1,000	800
10. ∑(Temporary non-)Controllable costs[14][15]	1,650	1,200

Step 2: Application of the efficiency score

Based on the pre-calculated efficiency score, as a result of a national efficiency benchmarking, we can determine the DSO's inefficiencies, which it has to eliminate over the regulatory period. Therefore, we define the controllable costs and temporarily non-controllable costs.

	DSO A	DSO B
11. Efficiency score	100%	90%
12. Inefficiencies (100% – 11.)	0%	10%
13. Temporally non-controllable costs (10. * 11.)	1,650	1,080
14. Controllable costs (10. * 12.)	0	120
15. Distribution parameter[16]	20%	20%
16. Controllable costs in the first year of the regulatory period (14. * (1 – 15.)	0	96

Since DSO A has been given an efficiency score of 100%, it does not have any inefficiencies to remove over the regulatory period. The controllable costs are therefore 0, while the temporarily non-controllable costs are 1,650 units. DSO A is not an outlier at the efficiency benchmarking and there is therefore no efficiency bonus.

Since DSO B has been given an efficiency score of 90%, it must remove inefficiencies of 10% over the regulatory period. The controllable costs are therefore 120 in total; for the first

[12] The return on equity is calculated on the basis of the costs of the tangible assets financed by equity multiplied by the rate of return on equity of 6.91%.
[13] Defined by cost catalogue.
[14] Separated into a controllable and temporally non-controllable part by using the determined efficiency score.
[15] Parts of positions No. 1., 2. and 7. are included at No. 9.
[16] Value at the first year of the regulatory period.

year of the regulatory period there are controllable costs using the distribution parameter of 80% (1-20%)*120, i.e. 96 units. The temporarily non-controllable costs are therefore 1,080 units. DSO B is not an outlier at the efficiency benchmarking and there is therefore no efficiency bonus.

Step 3: Determination of other revenue components

We have already mentioned that DSO A and DSO B are not outliers and therefore they will not get an efficiency bonus. The consumer price index at the base year was 100, the index of the first year was 101. As a fictional value for the productivity factor, we assume a value of 0.5%. Due to new investments at the first year of the regulatory period, DSO A gets a capital cost mark-up of 100, DSO B of 200. As a result of the quality regulation, we assume for DSO A a value of 50 and for DSO B a value of -100. The volatile costs of the base year have a value of 200 for DSO A and 100 for DSO B. At the first year of the regulatory period the volatile costs of DSO A are 300. For DSO B the volatile costs are on the same level as they are at the base year. The balances of both regulatory periods are assumed with 0.

	DSO A	DSO B
17. Efficiency bonus	0	0
18. Consumer price index in the base year	100	100
19. Consumer price index in first year of regulation	101	101
20. Development of prices (19./18.)	1.01	1.01
21. Productivity factor[17]	0.5%	0.5%
22. Correction factor for development of prices and productivity in first year of regulation (20. – ((1 + $21.^{1}$)– 1)	1.005	1.005
23.Capital cost mark-up	100	200
24. Quality element	50	-100
25. Volatile costs in base year	200	100
26. Volatile costs in first year of regulation	300	100
27. Change of volatile costs (26. – 25.)	100	0
28. Regulatory account balance	0	0

Step 4: Final calculation of the revenue cap

For the determination of the revenue cap, the DSOs in principle apply the following formula:

$$RC_t = C_{pnc,t} + (C_{tnc,t} + (1 - D_t) * C_{c,t} + \frac{B_0}{T}) * (\frac{CPI_t}{CPI_0} - PF_t) + CCT_t + Q_t + (VC_t - VC_0) + S_t$$

Therefore, we get a revenue cap for the first year of the regulatory period of:

	Revenue cap for the first year of the regulatory period
DSO A	1,000 +(1,650 +(1 – 20%)*0 + $\frac{0}{5}$)*($\frac{101}{100}$ – 0.5%)+ 100 + 50 +(300 – 200)+ 0 =2,908.25
	9. +(13. +(1 – 15.)*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + $21.^{1}$) – 1))+ 23. + 24. +(26. – 25.)+ 28.
DSO B	800+(1,080+(1 – 20%)*120 + $\frac{0}{5}$)*($\frac{101}{100}$ – 0.5%)+ 200 – 100 +(100 – 100)+0 =2,081.88
	9. +(13. +(1 – 15.)*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + $21.^{1}$) – 1))+ 23. + 24. +(26. – 25.)+ 28.

Table 13 – Revenue cap for the first year of the regulatory period (Germany)

[17] Assumed fictional value.

If the permanently non-controllable costs, the consumer price index, the capital cost mark-up, the quality element, the volatile costs or the balance of the regulatory account change in the course of the regulatory period, the revenue cap is adjusted accordingly.

Assuming that all components of the formula stay constant during the other years of the regulatory period except of the reduced (inefficient) controllable costs, we have following calculation at the last (fifth) year of the regulatory period:

	Revenue cap for the last year of the regulatory period
DSO A	1,000 +(1,650 +(1 – 100%)*0 + $\frac{0}{5}$)*($\frac{101}{100}$ – 2.53%)+ 100 + 50 +(300 – 200)+ 0 =2,908.25
	9. +(13. + 0*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{5}) – 1))+ 23. + 24. +(26. – 25.) + 28.
DSO B	800 +(1,080 +(1 – 100%)*120 + $\frac{0}{5}$)*($\frac{101}{100}$ – 2.53%)+ 200 – 100 +(100 – 100)+ 0 =1,985.4
	9. +(13. +0*14. + $\frac{17.}{5}$)*($\frac{19.}{18.}$ – ((1 + 21.^{5}) – 1))+ 23. + 24. +(26. – 25.) + 28.

Table 14 – Revenue cap for the last year of the regulatory period (Germany)

So, in this case DSO A could keep the revenue level, while DSO B has to eliminate the (inefficient) controllable costs.

Annex 5.17 Case Study – Lithuania

National Energy Regulatory Council (hereinafter – NERC)[18] applies different methodologies for setting allowed revenues for transmission system operators and distribution system operators (hereinafter – DSO) in the natural gas sector and the electricity sector, however, the main principles are the same. Therefore, the case study for setting the revenue cap[19] for a natural gas DSO is provided below.

A five-year regulatory period is being applied for the natural gas undertakings regulated by NERC. The revenue cap consists of economically justified costs (including OPEX (where personnel costs are evaluated separately), technological needs, depreciation costs and taxes) and ROI. Moreover, an incentive scheme is in place, which allows DSOs to earn additional profit if the company reduces its operational expenditures.

The detailed example[20] for establishing the forecasted distribution volumes, economically justified costs and ROI is provided below.

Forecasted distribution volumes of natural gas

Forecasted distribution volumes are established considering the distributed volumes during the previous regulatory period as well as the forecasted volumes provided by distribution system users. Illustrative figures are shown in Figure 4. As there is a visible stabilisation in distributed volumes in the year (t-2) – (t) Q is set as the average of this period: ((7,400+7,300+7,500)/3=7,400). Accordingly, Q for the year (t+1) is set as 7,400 GWh in this example.

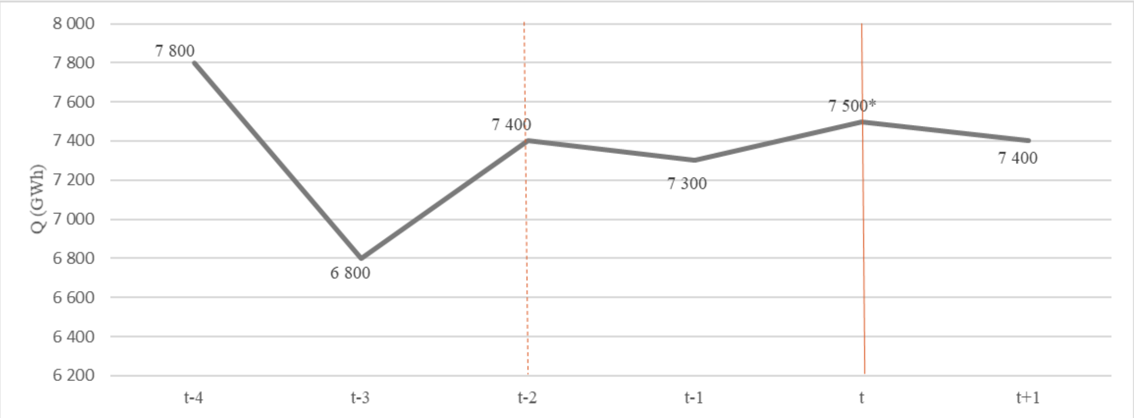

Figure 4 – Establishment of forecasted distribution volumes of natural gas (Lithuania)
*Expected Q for the year t

The calculation of economically justified costs for the first year of regulatory period

For the first year of regulatory period ***OPEX (excluding personnel costs)*** is set considering costs incurred in previous year[21], the inflation rate (I) for years (t-1) and (t) and the efficiency coefficient (e) which is 1%. OPEX (excluding personnel costs) is calculated according to the formula:

[18] From 1st of July 2019 according to Law on Energy of the Republic of Lithuania National Commission for Energy Control and Prices of the Republic of Lithuania will be renamed to Energy Regulatory Council (ERC).
[19] NERC used to set price caps for regulated services until the 1st of January 2019. However, the changes in the Law on Natural Gas of the Republic of Lithuania came into force from the 1st of January 2019. Therefore, NERC will be setting revenue caps for regulated services instead of price caps.
[20] Only illustrative figures are provided which do not reflect the real cost level of Lithuanian DSO.
[21] OPEX (excluding personnel costs) set by NCC and factual OPEX (excluding personnel costs) are compared and the lower value is used in calculations.

$$OPEX_{(t+1),(excl.\ personnel\ costs)} = OPEX_{(t-1),(excl.\ personnel\ costs)} \times (1+\frac{I_{(t-1)}-e}{100}) \times (1+\frac{I_{(t)}-e}{100})$$

The example for OPEX (excluding personnel costs) is provided in the table below.

OPEX (excluding personnel costs) in the year (t-1),	8,000
Inflation (%) in the year (t-1)[22]	3,5
Inflation (%) in the year (t)	2
OPEX (excluding personnel costs) in the year (t+1),	8,282

Table 15 – Calculation of OPEX (excluding personnel costs) (Lithuania)

Technological needs consist of fixed technological needs (natural gas consumed by the DSO as fuel in gas stations) and variable technological needs (technological losses). Technological needs for the year (t+1) are calculated according to the technological needs in the previous four years, both factually incurred and set by NERC. In the example below, fixed factual technological needs are higher than set by NERC, therefore the average between set and factual fixed technological needs are set for the year (t+1) – 122 GWh. Variable technological needs are calculated considering the factual ratio to distributed volumes of natural gas (0,65 %) and forecasted distribution volumes for the year (t+1) (7,400 GWh): 7,400*0,0065=48 GWh.

Year of the regulatory period	t-4	t-3	t-2	t-1	Average	**t+1**
Fixed technological needs						
Set by NCC, GWh	117	117	118	120	118	**122**
Factual, GWh	124	126	128	126	126	
Variable technological needs						
Set by NCC, GWh	85	70	62	63	70	**48**
Factual, GWh	69	47	42	34	48	
Factual losses in percentage to Q	0.88	0.69	0.57	0.47	0.65	**0.65**

Table 16 – Calculation of technical needs (Lithuania)

Technological costs are set by multiplying the technological needs (122+48=170) to the forecasted price of natural gas (including transmission price) for the year (t+1). For example, if the forecasted price is €30 /MWh, technological costs equal to €5,100 thousand (170×30=5 100).

Depreciation is calculated using the straight-line method according to the depreciation periods for regulated long-term assets set by NERC. Changes in depreciation evaluates DSO investments which are approved by NERC.

Long term assets	Depreciation (Gas sector)	Depreciation (Electricity sector)
Buildings	25–70	15-70
Pipelines/electricity lines*	55–75	40-55
Meters	9–12	12-16
Other infrastructure related to pipelines/electricity lines	15–20	15-35
Machinery and equipment	5–25	5-50
Other devices	4–10	5-10
Transport means	7	7
Software	4	4
Office inventory	6–10	6-10

[22] Where the inflation rate is less than 1, OPEX (excluding personnel costs) is set as OPEX (excluding personnel costs) of previous year (t-1).

Other long-term assets	6–10	6-10

Table 17 – Depreciation of periods applied by NCC (Lithuania)

*For distribution pipelines the depreciation period of 55 years is applied.

Personnel costs are calculated similarly to the other OPEX, yet the OPEX (personnel costs) for previous year[23]and average change in personnel costs in Lithuania (ΔW) for the year (t) and (t+1) are evaluated:

$$OPEX_{(t+1),(\,personnel\ costs)} = OPEX_{(t-1),(\,personnel\ costs)} \times (1 + \frac{\Delta W_{(t)} - e}{100}) \times (1 + \frac{\Delta W_{(t+1)} - e}{100})$$

OPEX (personnel costs) in the year (t-1), TEUR	10,000
ΔW (%) in the year (t)	9
ΔW (%) in the year (t+1)	7.5
OPEX (personnel costs) in the year (t+1), TEUR	11,502

Table 18 – Calculation of OPEX (personnel costs) (Lithuania)

Taxes are evaluated accordingly to the changes in legal acts. For example, in 2017, the Law on Natural Gas of the Republic of Lithuania was changed, and it was foreseen that low- and medium-pressure pipelines are no longer considered as real estate. This legal change led to decrease in real estate taxes paid by DSOs and a fall in total taxes by 50% for the main DSO.

Other costs arriving from factors which cannot be affected by the DSO are provided by the DSO and must be justified to be approved by NERC.

RAB. Only those investments which are approved by NERC are included into the RAB. Moreover, there are some restrictions foreseen which prohibit inclusion into the RAB:

- The value of goodwill;
- Investment assets;
- Financial assets;
- Deferred tax asset;
- Research;
- Study and similar intangible assets;
- The leased assets, assets under construction[24];
- The value of fixed assets created by the funds of the European Union;
- Grant subsidies;
- Equivalent funds or connection fees by natural gas customers;
- The value of a fixed asset recognised as ineffective investment by NERC;
- The residual value of an item of non-current asset that is no longer used after the investments for reconstruction of this item;
- The value of other long term assets not necessary to perform safe and efficient regulated activity;

Finally, only non-revalued assets are included into RAB.

For electricity transmission and distribution companies, the Long-Run Average Incremental Cost (LRAIC) method is applied for setting RAB, depreciation costs and ROI.

ROI is calculated as RAB multiplied by WACC. In WACC calculation cost of debt and equity risk premium are evaluated:

[23] OPEX (personnel costs) set by NCC and factual OPEX (personnel costs) are compared and the lower value is used in calculations.
[24] Except projects of common interest by the transmission system operator.

$$WACC = R_d \times W_D + R_e \times \frac{1}{1-m} \times W_E$$

R_d - cap of cost of debt (interest rate), percent; W_D - share of debt capital (optimal capital structure); W_E – share of equity capital (optimal capital structure); m - tax rate;
Return on equity, percent: $R_e = R_f + \beta \times R_{erp}$;
R_f - equity risk premium; R_{erp}- the sum of the equity risk premium of the country with the developed capital market (the US) and the additional market risk premium of Lithuania (last 20 years); levered β - Beta coefficient.

All data used in WACC calculations, except actual cost of debt of an individual company, is published on the NERC website[25]. Until 2019, the WACC was set for an entire regulatory period. However, during the next regulatory period, the WACC is adjusted each year in accordance with changes in DSO's cost of debt. For the main DSO, WACC is 3.58% for 2019.

Where RAB is €190 million and WACC is 3.58%, the ROI equal to €6,802 thousand (190,000×0.0358) is calculated.

Calculation of revenue cap. The allowed revenue level is calculated as the sum of all economically justified costs and ROI.

Indicator	Cell number / formula	Unit	Value
OPEX (excluding personnel costs)	1	Thousand EUR	8,282
Technological costs	2	Thousand EUR	5,100
Depreciation costs	3	Thousand EUR	9,202
OPEX (personnel costs)	4	Thousand EUR	11,502
Taxes	5	Thousand EUR	700
Economically justified costs	**6 = (1+2+3+4+5)**	Thousand **EUR**	**34,786**
ROI	7	Thousand EUR	6,802
Revenue cap	**8 = (6+7)**	Thousand **EUR**	**41,588**

Table 19 – Calculation of revenue cap (Lithuania)

Adjustments within regulatory period
The revenue cap may be adjusted once a year subject to the change in the inflation rate, personnel costs, volumes of distributed natural gas, investments by the DSO as agreed with NERC or deviations by the DSO from the indicators determined in methodology (natural gas price for technological losses, changes in actual cost of debt, revenue deviations justified by the DSO, etc.).

Incentive mechanism
NERC applies an incentive scheme which allows the DSO to earn additional profit if it reduces operational expenditures. The evaluation of efficiency is carried out in 2+2+1 (year of regulatory period) scheme. The example of the evaluation of efficiency for the regulatory period is provided in Figure 5.

[25] https://www.regula.lt/en/Pages/wacc-gas.aspx

In this example, actual ROI is higher than set by NERC in the 2nd (by value X) and the 3rd (by the value Y) and 4th (by value Z) year of regulatory period. The assumption is made that the differences X, Y and Z are due to efficiency in OPEX (E). In this case, the ROI for the regulatory period is increased by the value ((X+Y+Z)/2) as additional profit regarding efficiency in OPEX. The other half of difference in ROI is derived from allowed revenue.

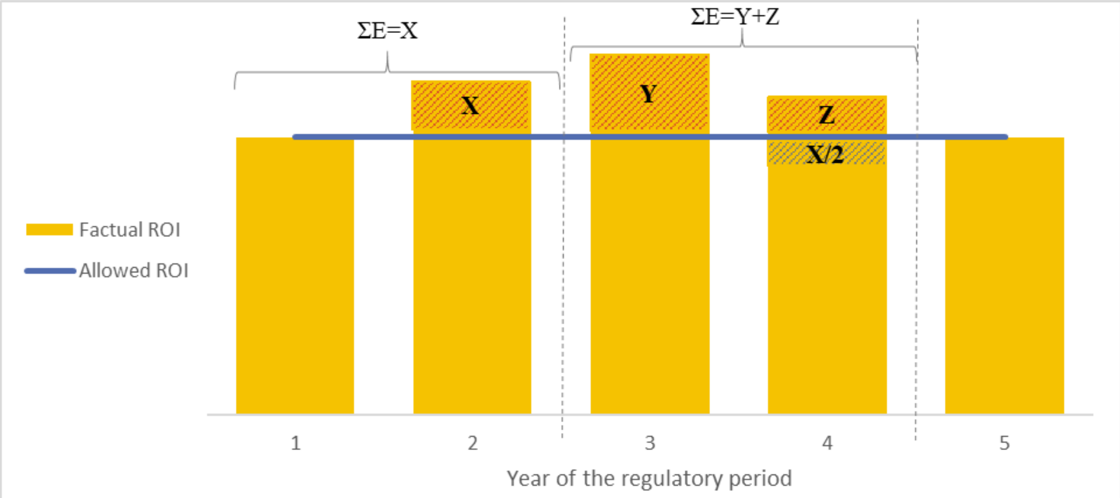

Figure 5 – for Evaluation of a DSO's efficiency (Lithuania)

The evaluation of efficienty in the 1st year of the regulatory period is performed likewise, yet the differences of ROI in the 3rd–5th year of the previous regulatory period are evalued.
Where the ROI exceeding the level set by NERC return is split over a period of more than one year, the value of the money is estimated. The value of money is subject to the cap of cost debt, as indicated NERC's website[26].

Transmission/distribution tariffs which do not exceed the revenue caps set by NERC are calculated by the TSO/DSOs according their methodologies.

[26] https://www.regula.lt/en/Pages/wacc-gas.aspx

Annex 5.19 Case Study – Netherlands

Below we present a small example of how revenue caps are set for DSOs in the Netherlands. As this is done in the same way for electricity and for gas; here we deal with gas exclusively. The example is simplified and data and numbers below are fictitious. Note that Dutch regulatory periods legally have a length of three to five years. The exact length of a specific period is set each time again and each time the base year is the average of the three years t-4, t-3, and t-2, where t is the starting year of the period. However, for sake of simplicity below we assume that the base year is just t-2. The current period started in 2017 (so with lies two years before the first year of a period). The current period started in 2017 and lasts five years, i.e. it ends 31 December 2021. Our example refers to this period.

We assume that the real WACC for that period is set to 3% and that for the preceding period this is 5%. Suppose we have a consumer price index (CPI) of 1% for all years.

Let A, B, and C be three DSOs. For each DSO the revenue cap is calculated by bringing the DSOs in a situation of yard stick competition. To this end, we take the following steps for each DSO individually:

1. Calculate its realised income in the year 2016.
2. Calculate its expected efficient cost level for the year 2021.
3. Set its x-factor such that its allowed revenues develop gradually from its realised income in 2016 to its expected efficient cost level in 2021. With gradually, we mean that the allowed income for year t is equal to its allowed income for year t-1 adjusted (multiplied) by its x-factor and CPI.

Note that x-factors are set individually and can be negative as well (denoting a yearly rise in real allowed revenues). Also note that we do not use benchmark scores like for the regulation of Dutch TSOs.

Below we elaborate on each of these steps.

<u>Step 1: Calculate realised incomes in the year 2016 for each DSO</u>
We do this just before the regulation period 2017-2021 starts. So, suppose we are in 2016 and that we have the following realised data for 2015/2016 for the DSOs:

	A		**B**		**C**	
Connection category	**Volume 2015**	**Tariff 2016 (euro)**	**Volume 2015**	**Tariff 2016 (euro)**	**Volume 2015**	**Tariff 2016 (euro)**
G4: 0-4 m3/h	1,000	100	2,000	80	5,000	80
G6: 4-6 m3/h	200	150	300	100	1,000	120
G10: 6-10 m3/h	100	200	300	110	500	140

For “Volume” the year 2015 is selected as this is the most recent year for which realised volumes are known just before the start of the period (the period is configured in 2016). Note that the output of a DSO is fully characterised by its volumes for connection categories. That is, no other types of output are considered, give or take that for electricity we also have a quality parameter, but in this example we abstract from that.

The realised incomes are calculated as the sum the volume*tariff products for each DSO:

	A	**B**	**C**
[1] Realised income 2016 (euro)	1,000*100 + 200*150 + 100*200 = 150,000	2,000*80 + 300*100 + 300*110 = 223,000	5,000*80 + 1,000*120 + 500*140 = 590,000

Step 2: Calculate expected efficient cost for each DSO for the year 2021

In order to estimate the efficient costs for 2021, we first estimate the costs for 2016. We estimate this as the (indexed) cost made in 2015 as this is the most recent year for which we have approved annual accounts.

The realised TOTEX is calculated as follows. Suppose we have:

	A	B	C
[2] OPEX 2015 (euro)	60,000	180,000	200,000
[3] RAB 2015 (euro)	900,000	1,000,000	4,000,000
[4] Average lifetimes (years)	40	39	42

where average lifetimes are based on technical lifetimes.

Then we calculate:

	Calculation	A	B	C
[5] OPEX 2015 (euro)	[2]	60,000	180,000	200,000
[6] CAPEX depreciation (euro)	[3]*(1/[4])	22,500	25,641	95,238
[7] CAPEX WACC (euro)	[3]*3%	27,000	30,000	120,000
[8] Cost 2015 (euro)	[5]+[6]+[7]	109,500	235,641	415,238
Cost 2016 (euro)	[8]*CPI	110,595	237,997	419,390

So, the total cost 2016 of the sector (A, B, and C together) is 767,982 euro [9]. Note that in [7] we use the WACC for the period 2017-2021.

Next, we calculate the estimated output for each DSO in the year 2021. The expected output of a DSO is calculated as the weighted sum of its expected volumes of the connection categories in 2021, where these expected volumes are set equal to the realised volumes in 2015, and the weights are equal to the sector average tariff 2016 for the connection category. For this sector average tariff 2016 we have:

	A		**B**		**C**		**Sector**
Cat.	**Volume 2015**	**Tariff 2016 (euro)**	**Volume 2015**	**Tariff 2016 (euro)**	**Volume 2015**	**Tariff 2016 (euro)**	**Average tariff 2016 (weights)**
G4	1,000	100	2,000	80	5,000	80	(1,000*100 + 2,000*80 + 5,000*80) / (1,000 + 2,000 + 5,000) = 82.50
G6	200	150	300	100	1,000	120	(200*150 + 300*100 + 1,000*120) / (200 + 300 + 1,000) = 120.00
G10	100	200	300	110	500	140	(100*200 + 300*110 + 500*140) / (100 + 300 + 500) = 136.67

With this we calculate the DSOs' outputs:

	Weight	**A**	**B**	**C**
Output G4	82.50	82.50*1,000	82.50*2,000	82.50*5,000
Output G6	120.00	120.00*200	120.00*300	120.00*1,000
Output G10	136.67	136.67*100	136.67*300	136.67*500
Total output 2016		120,167	242,001	600,835
[10] Estimated output 2021		120,167	242,001	600,835

So what we do here, is to set the estimated output for 2021 equal to the (partly estimated) output in 2016, i.e. to estimate the efficient cost level in 2021 we simply assume that output will be stable throughout the period 2017-2021. The total estimated sector output for 2021 then is the sum of this: 963,003 units of output [11]. The efficient cost (sectorial) is than [9] / [11] = 767,982 / 963,003 = 0.797 euro per unit of output [12].

With this the expected efficient cost DSOs make in 2021 reads:

	Calculation	**A**	**B**	**C**
[13] Exp. Eff. Cost 2021 (euro)	[10]*[12]	95,773	192,874	478,865

<u>Step 3: Setting an x-factor for each DSO</u>

With Steps 1 and 2 we finally calculate x-factors for the regulatory period 2017-2021 as:

	Calculation	**A**	**B**	**C**
[14] Realised income 2016 (euro)	[1]	150,000	223,000	590,000
		↓	↓	↓
x-factor period 2017-2021	$1-([15]/[14])^{1/5}$	8.58%	2.86%	4.09%
		↓	↓	↓
[15] Exp. Eff. Cost 2021 (euro)	[13]	95,773	192,874	478,865

So, for example, this means for A that they start the regulatory period with allowed revenues of 150.000 * (1-8.58%) = 137,130 euro in 2017 and end the period in 2021 with allowed revenues of 150,000 * $(1\text{-}8.58\%)^5$ = 95,773 euro, i.e. its assumed efficient cost level.

Annex 5.23 Case Study – Portugal

Incentive for the integration of low voltage installations in smart grids

Introduction

This case study focuses on an incentive created and applied by ERSE to promote the integration of low voltage (LV) installations (supply points) into smart grids. It can also be seen as an incentive for "availability of smart services". This section will present the main motivations behind this incentive, the installation requirements to access it, the remuneration design and the rationale that underpins the valuation of this incentive scheme.

The implementation of smart grids is a fundamental component of the European internal energy market. The development of smart grids can promote better demand conditions and competition in retails markets. Other benefits, such as the development of new value-added services for consumers, the promotion of energy efficiency, reduction of emissions and more efficient grid management and operation are paramount as well.

Aiming to support the development of smart grids in Portugal, in August 2019 ERSE published Regulation n.º 610/2019[27] ("Regulation for Smart Grid Services") which sets the terms and rules applicable to services delivered by LV Distribution System Operators (DSOs) in the context of smart electricity distribution grids.

This regulation also establishes an output-based incentive (ISI), which aims to encourage LV DSOs to deliver smart grid enabled value-added services to consumers. Under the incentive, LV DSOs receive a fixed annual amount (for a fixed number of years) per LV supply point that provides a defined set of smart grid services to consumers, thus deeming those points to be "integrated into smart grids". The value of this financial incentive is based on the sharing of the net benefits these services generate between LV DSOs and consumers.

Motivation for this incentive

In Portugal, several factors were hindering the development of smart grid services for LV consumers. Firstly, concerning the infrastructure component, no national decision has been taken requiring a smart meter rollout, despite a positive cost-benefit analysis.

In addition, due to the national legal constraints, part of the investments required to develop these services, such as investment in smart meters, are not included in the regulatory asset base, leaving the LV DSOs with no direct incentive to install them, since they are not able to recover their costs through allowed revenues.

Finally, the regulatory methodologies applied to the LV distribution activity may not be effective enough in providing the adequate economic signals to lead LV DSOs to develop these services. In mainland Portugal, the LV distribution activity is regulated through a price cap on total expenditure (TOTEX). Despite having many advantages, given the specific national legal framework in place, this methodology has not provided enough indirect incentives for LV DSOs to develop innovative services when there are clear externalities that go beyond this activity. A relevant share of the consumer benefits generated by these services/investments, such as energy savings, go beyond the traditional decrease in operational expenses achieved by the LV DSOs, and thus are not internalised by them. Moreover, LV DSOs share part of their cost savings with consumers, both through annual efficiency targets applied to the entire cost base and through periodic revisions of the cost

[27] https://www.erse.pt/media/x2mpii1a/regulamento-n-º-610_2019.pdf. This regulation was published following a public consultation process: https://www.erse.pt/atividade/consultas-publicas/consulta-p%C3%BAblica-n-%C2%BA-70/.

base at the beginning of each regulatory period. Thus, LV DSOs faced a limited natural incentive to develop and deliver these services for LV consumers.

Therefore, the new ISI incentive was designed to incentivise LV DSOs to develop and to deliver to consumers a number of services that unlock the benefits of smart grid integration.

Installation requirements
In order to qualify for this incentive, that is, in order to be classified as “integrated in smart grids,” each LV installation must be able to deliver a set of services. These services include, among others:

- remote reading and availability of detailed consumption data;
- active electricity consumption alerts and comparison with previous years;
- availability of the installation's active power load diagrams;
- availability of data on quality of service and services associated with the supply of electricity, such as adjustment of contracted power; and
- remote activation/deactivation of supply.

Remuneration and Design
As mentioned above, the ISI incentive is an output-based incentive related to the availability of smart grid services. The ISI incentive is a reward applied to eligible LV installation, through an amount paid during several years.

Therefore, the incentive is calculated on an annual basis and is applied for each LV supply point that is deemed to have been integrated into smart grids, by virtue of providing the set of services established in ERSE’s regulation, as per above. A year-on-year increase in the number of integrated supply points has a positive impact on the global value of the incentive.

The parameters, namely the duration of the incentive and the annual amount, can be revised at the beginning of each regulatory period. The incentive is presented in more detail below.

For each LV DSO, the total value of the incentive for each year w over the period T_w is calculated with the following expression:

$$ISI_{LV,W}^{LVOj} = \Delta NI_w^{LVOj} \times K_w^{LVOj} \times T_w$$

Where:

$ISI_{LV,W}^{LVOj}$ Total amount of incentive for year *w*, awarded to LV DSO j (LVOj).

W	Reference year for application of the incentive.
ΔNI_w^{LVOj}	The difference between the number of LV installations deemed to be integrated in smart grids on 31 December of year *w* and on 31 December of year *w*-1.
K_w^{LVOj}	Parameter that represents the annual value of the incentive $ISI_{LV,t}^{LVOj}$ for year *w* (or the benefit shared with the LV DSO).
LVO^j	The LV DSO eligible for the incentive.
T_w	Parameter that represents the number of years of application of the incentive.

At the end of Tw, the value of the parameter K_w^{LVOj} is zero.
It is relevant to present the formula to calculate the total annual value of the incentive that each LV DSO receives each tariff year, t.

$$TISI_{LV,t}^{LVOj} = \sum_{w=2019}^{t-2} \frac{ISI_{LV,W}^{LVOj}}{T_w}$$

Thus, from the 2022[28] network tariffs onward, the ISI amounts will be included in the DSO's annual allowed revenues (relative to 2020 with a 2-year delay).

The following figure illustrates the incentive's structure and the annual amounts for a given LV DSO, for each year of increase in integrated installations (ISI 2020, ISI 2021, etc.), until most of its LV supply points are integrated into smart grids. In more general terms, the maximum amount of the incentive is not estimated to exceed 3% of the annual allowed revenues of the LV distribution activity.

Figure 6 – Structure and simulated range of annual ISI incentive amounts (Portugal)

Main parameters

The fundamental parameters the regulator must define are the annual value of the incentive (K_w^{LVOj}) and the incentive's length (T_w). To define them[29], ERSE reviewed the most recent cost benefit analysis of a smart meter rollout in Portugal, trying to quantify the benefits generated by the services that enable access to this incentive, for each LV installation. Throughout this exercise, ERSE adhered to the following main principles:

- Ensuring that the value of this incentive is closely related to the LV DSOs' performance in developing and delivering smart-grid services with explicit net benefits to consumers[30];
- Guaranteeing that consumers keep a significant portion of the benefits, while at the same time providing an adequate incentive for LV DSOs to provide these services, but with the lowest possible impact on network tariffs; and
- Allowing for a periodic review of the parameters, to incorporate technological developments, seeking to maximise continuously the value for new LV installations integrated in smart grids. At the same time, trying to limit regulatory risk by fixing parameters for each reference year (w) of smart grid integration and establishing parameters for an entire regulatory period.

[28] Despite being available since 2019, so far this incentive was only awarded to a small pilot project in Madeira Island. Even though there are currently more than 2 million supply points with smart meters, at the end of 2019 they were still unable to deliver the full set of services required to be eligible for this incentive.

[29] For further details about the parameters, please refer to the following document: https://www.erse.pt/media/h03d0s0k/proveitos-e-ajustamentos-2020.pdf.

[30] Cost benefit study on smart meter rollout, as established by Ordinance nº231/2013.

The initial parameters, set for the current regulatory period, were as follows:

Parameters	2019	2020
K_w^{OBTj} (euros)	5.00	5.08
T_w (number of years)	8	8

Table 20 – ISI parameters (Portugal)

The value of parameter T_w is based on the useful life, for accounting purposes, of the infrastructure, equipment and information systems required to deliver these services and to effectively integrate LV installations in smart grids.

As for parameter K, the idea was to share with LV DSOs a component of the overall benefits derived from their avoided costs. Investing in these services enables LV DSOs to avoid some distribution activity costs (such as manual readings and local operations), while generating positive externalities[31] for consumers. Since the LV DSOs would not otherwise benefit from a significant share of these avoided costs, which would be passed on to consumers due to the regulatory methodologies in place[32], this calibration of K would partially make up for that lost income, while allowing LV DSOs to profit from these investments.

At the same time, consumers will still capture most of the benefits, which would not be available if the LV DSOs did not invest in the development of these smart grid services.

The next figure illustrates the rationale behind the valuation of parameter K:

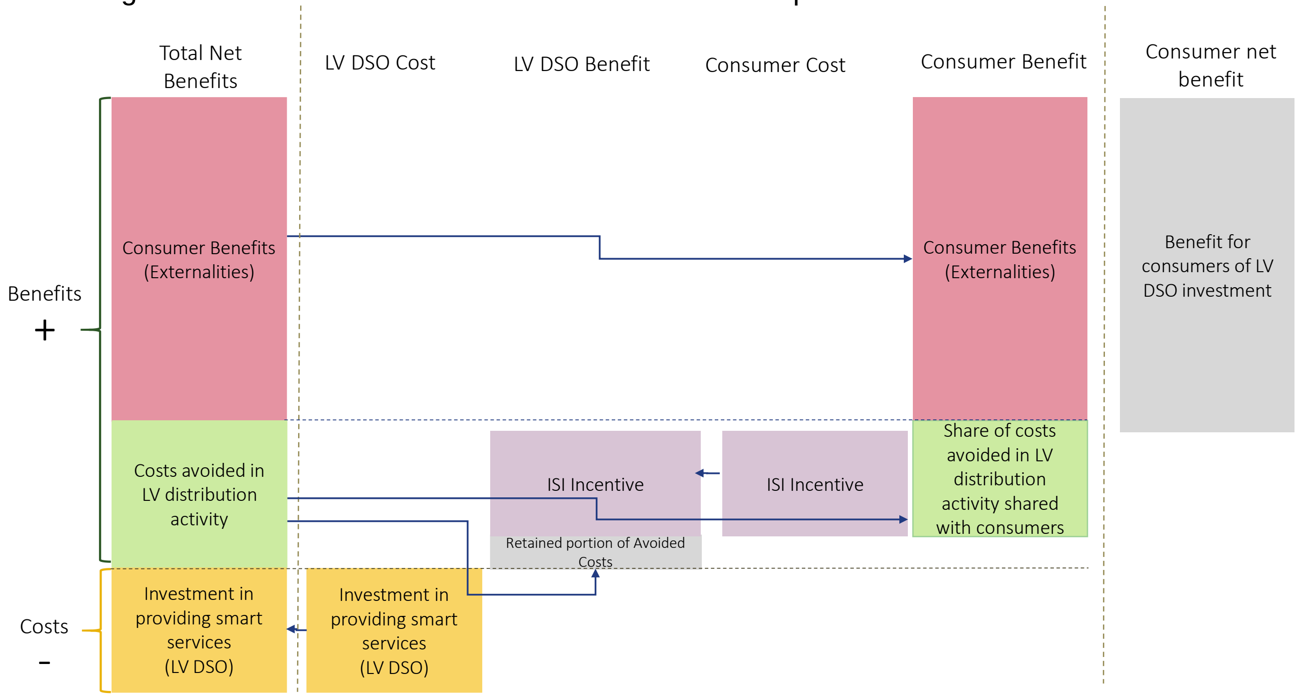

Figure 7 – Sharing costs and benefits of smart grid services (Portugal)

In summary, with these parameters the incentive ensures that the main benefits are kept by consumers. Furthermore, LV DSOs obtain enough benefits (both from the incentive and from retained cost savings) to compensate for the financial effort required to invest in the development and delivery of smart grid services.

[31] Such as savings from a more efficient electricity consumption.
[32] Through cost base revisions and application of efficiency targets.

Annex 5.27 Case Study – Spain

Introduction:
This case study describes the regulatory regime that applies to an electricity transmission company in Spain, in order to set its remuneration. It is based on the methodology established by Circular 5/2019, of 5 December, of Comisión Nacional de los Mercados y la Competencia (CNMC, the Spanish NRA). You can find further details in Circular 5/2019[33] and its justifying report[34].

The annual remuneration received by the transmission company "i" is calculated by summing up the components of the following formula for year "n":

$$\mathrm{R}_{\mathrm{n}}^{\mathrm{i}} = \mathrm{RI}_{\mathrm{n}}^{\mathrm{i}} + \mathrm{ROM}_{\mathrm{n}}^{\mathrm{i}} + \mathrm{REVU}_{\mathrm{n}}^{\mathrm{i}} + \mathrm{ID}_{\mathrm{n}}^{\mathrm{i}}$$

RI	Investment remuneration
ROM	Operation and maintenance (O&M) remuneration
REVU	Remuneration for the extended regulatory lifetime of assets
ID	Grid availability incentive

Once the annual remuneration has been calculated, if assets and other regulated resources have been used in other activities, an adjustment will be made. There is also a penalty that is applied if the recommended values of several economic and financial ratios are not met.

This annual remuneration and the adjustments, if any, determine the allowed revenue for the electricity transmission company.

Assets commissioned in year n, start receiving revenues in year n+2. This means that, if the calculation is made for year 2020; the last year considered is 2018. There are factors that compensate for this delay.

Application example:
A simplified fictional example of the application of the Spanish remuneration regime for an electricity transmission company is given.

For the sake of simplicity and given that both the investment and the O&M remuneration are based on the cost of individual assets, only six different asset types have been considered in this example. They are shown in the table below.

[33] https://www.boe.es/buscar/act.php?id=BOE-A-2019-18260
[34] https://www.cnmc.es/sites/default/files/2782083_19.pdf

Asset nº	Technical characteristics	Commissioning	Location	Regulatory lifetime	Audited cost (€)	Other characteristics
1	Overhead single duplex transmission line of 10 km, 400 kV and 1,000 MVA	1st January 2018	Iberian Peninsula	40 years	3,100,000	20% was financed and transferred by a third party
2	Conventional substation bay, 400 kV, 50 kA, all configurations	1st January 2018	Iberian Peninsula	40 years	900,000	-
3	Single-phase transformer (400/220 kV), 200 MVA	1st January 2019	Iberian Peninsula	40 years	1,800,000	-
4	Overhead single duplex transmission line of 8 km, 220 kV and 200 MVA	1st January 2019	Tenerife	40 years	4,200,000	EU subsidy of €2,000,000
5	Overhead single duplex transmission line of 10 km, 400 kV and 1,000 MVA	1st January 1978	Iberian Peninsula	40 years	Not necessary because its regulatory lifetime expires 31 December 2017	-
6	Underwater cable, 8 km, 132 kV, 100 MW	1st January 2018	Balearic Islands	40 years	4,500,000	Considered as a unique facility

Table 21 – Asset types (Spain)

The remuneration is calculated for the regulatory period that ranges from the 1st of January 2020 to the 31st of December 2025, the first in which the new methodology is used.

Step 1: determination of the investment remuneration (RI)
To calculate the investment remuneration (RI), we add the depreciation and the financial retribution terms for the assets that have not exceeded their regulatory lifetime. In this example, all assets receive investment remuneration except asset number 5 because it reached its regulatory lifetime (40 years) on the 31st of December 2017.

The magnitude of both terms, depreciation and financial retribution depends on the recognised value of the investments. To determine the recognised value of the investments, there are two different approaches, depending on whether the assets are considered as unique facilities or not.

For those assets not considered as unique facilities, the recognised value of investments can be calculated in three ways depending on the date of commissioning:

- For facilities commissioned prior to the 1st of January 1998: the recognised value of investment is considered as a whole, not asset by asset. It was set in 2016 by the Directorate General for Energy Policy and Mines.
- For facilities commissioned from 1st January 1998 to 31st December 2017: there is a recognised investment value for each asset, whose calculation is based on the methodology established by Royal Decree 1047/2013[35]. For those assets commissioned from 1st January 2015 on, the investment value is calculated as the average of the reference values and the audited cost of the asset.
- For facilities commissioned from 1st January 2018 to year n-2 (the case of our fictional example): there is an investment value for each asset, also calculated as the average of the reference values and the audited cost of the asset but a new limitation is introduced if the audited cost is higher than the reference value divided by 0.85. Circular 7/2019[36] of CNMC has established that the investment reference values for the regulatory period 2020-2025 are the ones established in the catalogue of Order IET/2659/2015[37], which are shown below, for the assets of the example.

[35] https://www.boe.es/buscar/act.php?id=BOE-A-2013-13766
[36] https://www.boe.es/buscar/act.php?id=BOE-A-2019-18262
[37] https://www.boe.es/buscar/act.php?id=BOE-A-2015-13487

Electricity transmission assets	$VI^{reference\ value}$	
Power lines	Variable term (€/km)	Fixed term (€)
Asset nº 1: 10 km, in Peninsula	298,437	-
Asset nº4: < 10 km, in Tenerife	404,937	824,267
Substation bays	Term in €/bay	
Asset nº2	1,043,909	
Transformers	Variable term (€/MVA)	
Asset nº3	9,835	

Table 22 – Electricity transmission assets (Spain)

The reference values for mainland assets are determined according to the average values considered as representative for the cost of each asset, whose technical design and operating conditions fit to the standards used in the Spanish mainland electricity system. The reference values for the assets located in non-mainland electricity systems can differ according to the particularities derived from their geographical location and isolation. In any case, the reference values will be calculated based on the regulatory information on costs.

For the assets considered as unique facilities, the investment reference values are not used, as these assets do not fit in the catalogue. Unique facilities are those whose design, operative and technical characteristics differ from the standards, namely underwater laying, direct current transmission lines, converter stations AC/DC, as well as remote control stations. Additionally, investments in pilot projects could also be considered as unique ones.

Circular 2/2019[38] sets the rate-of-return of investments based on a WACC methodology. For electricity transmission in the regulatory period 2020-2025, the rate-of-return takes a value of 5.58% (nominal pre-tax). There is an exception for year 2020, when the rate-of-return takes a value of 6.0033% according to the fourth Additional Provision of Circular 5/2019.

The formulas to calculate the investment remuneration for our fictional electricity transmission company, and the results obtained, are shown below:

Investment remuneration for assets in service from 1st January 2018 to year n-2

$$\mathbf{RI_n^i} = \sum_{\forall j \text{ of } i} RI_n^j$$

$$RI_n^j = A_n^j + RF_n^j$$

$$A_n^j = \frac{VI^j}{VU^j} \qquad RF_n^j = VN_n^j \cdot TRF_p$$

$$VN_n^j = VI^j - (k-2) \cdot \frac{VI^j}{VU^j}$$

$$VI^j = \left[\left(VI_{n-2}^{j,audited} + \frac{VI_{n-2,p}^{j,reference\ value} - VI_{n-2}^{j,audited}}{2}\right) \cdot \delta_j - AY^j\right] \cdot FRRI_{n-2}^j$$

$$FRRI_{n-2}^j = (1 + TRF_{APS})^{tr_j}$$

For unique facilities, this parameter is the investment value considered in the uniqueness request: $VI_{n-2}^{j,uniqueness\ request}$

j	asset
i	transmission company
n	year
p	regulatory period
A	depreciation
RF	financial remuneration
VI	investment value
VU	regulatory lifetime
VN	net investment value
TRF	rate-of-return
k	number of years from commissioning
$VI^{audited}$	audited investment cost
$VI^{reference\ value}$	reference investment value
δ	1 less the proportion financed or transferred by third parties
AY	public subsidies received
FRRI	remuneration delay factor
TRF_{APS}	rate-of-return of the year of the operating licence
tr	time remuneration delay: number of years between the date of the operating licence and the start of revenues

For each non unique asset, if there is a big difference between its audited cost and its reference value, the limits established in articles 7.3 and 7.4 of Circular 5/2019 will be applied to the recognised investment value.

In particular, if the transmission company is able to build an asset at an audited cost below its reference value, half of the difference between the reference value and the audited cost will be limited up to 12.5% of the audited cost. On the other hand, for assets built from the 1st of January 2018 onwards, if the audited cost is higher than the reference value divided by 0.85, the transmission company has to submit a technical audit justifying the high costs, and

[38] https://www.boe.es/buscar/act.php?id=BOE-A-2019-16639

the recognised investment value is calculated using the reference value plus the 12.5% of the reference value.

For unique assets, according to article 9 of Circular 5/2019, the recognised investment value cannot be higher than 25% of the investment value established in the uniqueness request. In this example, none of these limits are exceeded.

Asset	$VI^{audited}$ (€)	$VI^{reference\ value}$ (€)	δ	AY (€)	TRF_{APS}	tr***	FRRI	VI^{j}
Assets that start to receive remuneration in 2020								
1	3,100,000	2,984,370	0.8	0	6.503%	2.00	1.1	2,760,573
2	900,000	1,043,909	1.0	0	6.503%	2.00	1.1	1,102,477
6	4,500,000	5,000,000*	1.0	0	6.503%	2.00	1.1	5,387,872
Assets that start to receive remuneration in 2021								
3	1,800,000	1,967,000	1.0	0	6.503%	2.00	1.1	2,136,433
4	4,200,000	4,063,763	1.0	1,800,000**	6.503%	2.00	1.1	2,645,027
5	As the asset has exceeded its regulatory lifetime (40 years), it does not receive any investment remuneration							

* There are no reference values for unique facilities, this is the investment value of the uniqueness request ($VI_{n-2}^{j,\text{uniqueness request}}$).
** As the asset receives a subsidy from the EU, this value is 90% of the subsidy received, as established in article 7.2 of Circular 5/2019.
*** We assume that the date when it obtains the operating license and the date commissioning is the same.

				2020	2021	2022	2023	2024	2025
			TRF_P	6.0033%*	5.58%	5.58%	5.58%	5.58%	5.58%
Assets commissioned in 2018			k	2	3	4	5	6	7
1	VI_1	2,760,573	VN_1	2,760,573	2,691,559	2,622,545	2,553,530	2,484,516	2,415,502
	A_1	69,014	RF_1	165,725	150,189	146,338	142,487	138,636	134,785
	VU_1	40 years	RI_1	234,740	219,203	215,352	211,501	207,650	203,799
2	VI_2	1,102,477	VN_2	1,102,477	1,074,915	1,047,353	1,019,791	992,229	964,668
	A_2	27,562	RF_2	66,185	59,980	58,442	56,904	55,366	53,828
	VU_2	40 years	RI_2	93,747	87,542	86,004	84,466	82,928	81,390
6**	VI_6	5,387,872	VN_6	5,387,872	5,253,175	5,118,479	4,983,782	4,849,085	4,714,388
	A_6	134,697	RF_6	323,450	293,127	285,611	278,095	270,579	263,063
	VU_6	40 years	RI_6	458,147	427,824	420,308	412,792	405,276	397,760
Assets commissioned in 2019			k		2	3	4	5	6
3	VI_3	2,136,433	VN_3		2,136,433	2,083,022	2,029,611	1,976,201	1,922,790
	A_3	53,411	RF_3		119,213	116,233	113,252	110,272	107,292
	VU_3	40 years	RI_3		172,624	169,643	166,663	163,683	160,703
4	VI_4	2,645,027	VN_4		2,645,027	2,578,902	2,512,776	2,446,650	2,380,525
	A_4	66,126	RF_4		147,593	143,903	140,213	136,523	132,833
	VU_4	40 years	RI_4		213,718	210,028	206,339	202,649	198,959
Investment remuneration (€), RI				**786,634**	**1,120,912**	**1,101,336**	**1,081,761**	**1,062,186**	**1,042,611**

*According to the 4th Additional Provision of Circular 5/2019, for 2020, the rate-of-return has been established in 6.0033% for the first year of the first regulatory period in which this methodology applies (2020).
**Asset considered as unique facility.

Step 2: determination of the operation and maintenance remuneration (ROM)
To calculate the O&M remuneration (ROM) for a transmission company, we add the O&M remuneration for each of its assets in service.

For assets not considered as unique facilities, the O&M remuneration is based on reference values, multiplied by an efficiency factor. In this example, all assets receive O&M remuneration because all of them are in service as of 31 December 2018. The reference values for O&M are established by Circular 7/2019, and are shown in the table below for the asset types of the example:

Electricity transmission assets	**VOM**
Power lines	Variable term (€/km and circuit)
Assets nº 1,5: 10 km, in Peninsula	3,056
Asset nº4: < 10 km, in Tenerife	3,255
Substation bays	Variable term (€/bay)
Asset nº2	47,339
Transformers	Variable term (€/MVA)
Asset nº3	131

The calculation is made gathering the assets in families of electricity transmission assets, which are defined in the annex of Circular 5/2019. For each family of assets, there is an O&M reference value. In this fictional example, we have four different families of assets:

I. Overhead lines at 400 kV
II. Overhead line at 220 kV
III. Conventional substation bay at 400 kV
IV. Transformer with primary at 400 kV

For assets considered as unique facilities, the O&M remuneration is based on the value of operation and maintenance established in the uniqueness request and a beta factor that allows its adjustment to the actual cost. This parameter takes a value of 1 the first year and can be adjusted from the second year onwards, according to the information provided by the transmission agent to the NRA (CNMC). In no case, can the O&M remuneration for unique assets be higher than 25% of the value of operation and maintenance established in the uniqueness request.

The formulas to calculate the O&M remuneration for our fictional transmission agent, and the results obtained, are shown below:

O&M remuneration for assets in service

$$\mathbf{ROM_n^i} = \sum_{\forall F \text{ of } i} \mathrm{ROM}_{n,ccuu}^{F,i} \cdot \left(1 + \theta^i\right)$$

$$\mathrm{ROM}_{n,ccuu}^{F,i} = \sum_{\forall j \text{ of } F} \mathrm{ROM}_n^j \qquad \theta^i = \alpha \cdot \frac{\mathrm{ROM}_{k-1,ccuua}^i - \mathrm{ROM}_{k-1,ccuu}^i}{\mathrm{ROM}_{k-1,ccuu}^i}$$

$$\mathrm{ROM}_n^j = \mathrm{VOM}_p^j \cdot \mathrm{UF}_i \cdot \mathrm{FRROM}_p^j$$

$$\mathrm{FRROM}_p^j = \left(1 + \mathrm{TRF}_p\right)^{\mathrm{tr\_om}_j}$$

For **unique facilities**, the O&M remuneration is determined as:

$$\mathrm{ROM}_n^j = \mathrm{ROM}_{\text{uniqueness request}}^j \cdot \mathrm{FRROM}_p^j \cdot \beta$$

j	asset
i	transmission company
F	family of assets
n	year
p	regulatory period
k	first year of the regulatory period
n,ccuu	reference values of the year n
k-1, ccuu	reference values of the year k
k-1, ccuua	reference values of the year k-1
ROM	O&M remuneration
θ	O&M efficiency factor
α	parameter that allows companies to retain a percentage of the drop of reference values (incentive to promote cost efficiency)
VOM	O&M reference value
UF	number of assets
FRROM	O&M remuneration delay factor
$\mathrm{tr\_om}_j$	number of years O&M remuneration delay
$\mathrm{ROM}_{uniqueness}$	O&M remuneration established in the uniqueness request
β	parameter to adjust the O&M cost established in the uniqueness request to the actual cost

The aim of the efficiency factor (θ) is to adapt the O&M remuneration of transmission companies, calculated with the reference values of the previous regulatory period, to the remuneration calculated according to the reference values of the current regulatory period. If the companies are able to lower down their O&M costs during a regulatory period, the O&M reference values of the next regulatory period can be set lower, to allow customers benefit from this cost reduction. Nonetheless, the efficiency factor (θ) contains a parameter (alpha) that allows companies to retain a percentage of the drop of reference values, which serves as an incentive to promote cost efficiency.

In this example, the calculation of the efficiency factor is based on the O&M remuneration of year 2019 (year k-1, being k the first year of the regulatory period 2020-2025), calculated according to the reference values set in Order IET/2659/2015, and the O&M remuneration of year 2019 calculated according to the new reference values defined by Circular 7/2019. Notice that, for this fictional example, we use the only asset that was in service in 2017 (as to calculate 2019's remuneration we take into account assets in service up to 2017). This is asset number 5, which corresponds to an electricity transmission line.

The O&M reference value established by Order IET/2659/2015 for a transmission line of 10 km located in Iberian Peninsula is €3,106 per km and circuit. Taking into account that alpha takes a value of 0.5, as established in the 2nd Additional Provision of Circular 5/2019, and that the O&M reference value for the current regulatory period is €3,056 per km and circuit, the efficiency factor takes a value of 0.8%, as shown below:

$$\theta = 0.5 \cdot \frac{3{,}106 \frac{€}{\mathrm{km} \cdot \mathrm{circuit}} \cdot 10\mathrm{km} \cdot 1\ \mathrm{circuit} - 3{,}056 \frac{€}{\mathrm{km} \cdot \mathrm{circuit}} \cdot 10\mathrm{km} \cdot 1\ \mathrm{circuit}}{3{,}056 \frac{€}{\mathrm{km} \cdot \mathrm{circuit}} \cdot 10\mathrm{km} \cdot 1\ \mathrm{circuit}} = 0.008$$

				2020	2021	2022	2023	2024	2025
Family	Asset	TRF_P		6.0033%*	5.58%	5.58%	5.58%	5.58%	5.58%
Family I	1	tr_om=1 UF=1 VOM=30,560	$FRROM_{I,1}$	1.060	1.056	1.056	1.056	1.056	1.056
			$ROM_{I,1}$	32,395	32,265	32,265	32,265	32,265	32,265
	5	tr_om=0 FRROM=1 UF=1 VOM=30,560	$ROM_{I,5}$	30,560	30,560	30,560	30,560	30,560	30,560
Family II	4	tr_om=1 FRROM=1.056 UF=1 VOM=26,040	ROM_{II}		27,493	27,493	27,493	27,493	27,493
Family III	2	tr_om=1 UF=1 VOM=47,339	$FRROM_{III}$	1.060	1.056	1.056	1.056	1.056	1.056
			ROM_{III}	50,181	49,981	49,981	49,981	49,981	49,981
Family IV	3	tr_om=1 FRROM=1.056 UF=1 VOM=26,200	ROM_{IV}		27,662	27,662	27,662	27,662	27,662
ROM_{ccuu}				**113,136**	**167,961**	**167,961**	**167,961**	**167,961**	**167,961**
θ				**0.8%**					
O&M Remuneration for non-unique facilities (€)				**114,061**	**169,335**	**169,335**	**169,335**	**169,335**	**169,335**
Unique facility	6	ROM=55,000 tr_om=1	$FRROM_{unique}$	1.060	1.056	1.056	1.056	1.056	1.056
			β**	1	0.98	0.98	0.98	0.98	0.98
			ROM_{unique}	58,302	56,908	56,908	56,908	56,908	56,908
O&M Remuneration (€), ROM				**172,363**	**226,242**	**226,242**	**226,242**	**226,242**	**226,242**

*According to the 4th Additional Provision of Circular 5/2019, for 2020, the rate-of-return has been established in 6.0033% for the first year of the first regulatory period in which this methodology applies (2020).
** We assume that from 2021 on, the actual O&M costs of this unique facility are lower than the ones established in the uniqueness request.

Step 3: determination of the remuneration for extending the regulatory lifetime (REVU)

There is only one asset that receives remuneration for extending its regulatory lifetime, asset number 5, which is an electricity transmission line commissioned the 1st of January 1978. Consequently, its regulatory lifetime (40 years) ended the 31st of December 2017, and, in 2018, as it is still in service, it only receives O&M remuneration and this complement.

Remuneration for extending the regulatory lifetime of assets

$$\mathbf{REVU}_n^i = \sum_{\forall j \text{ of } i} \mathrm{REVU}_n^j$$

$$\mathrm{REVU}_n^j = \mu_n^j \cdot \mathrm{ROM}_n^j$$

x ≤ 5 years	$\mu_n^j = 0.30$
6 ≤ x ≤ 10 years	$\mu_n^j = 0.30 + 0.01 \cdot (x-5)$
11 ≤ x ≤ 15 years	$\mu_n^j = 0.35 + 0.02 \cdot (x-10)$
x > 15 years	$\mu_n^j = 0.45 + 0.03 \cdot (x-15)$

j	asset
i	transmission company
n	year
x	years exceeding the regulatory lifetime
μ	exceeding regulatory lifetime coefficient
ROM	O&M remuneration

Asset		2020	2021	2022	2023	2024	2025
1	$REVU_1$	It hasn't exceeded its regulatory lifetime					
2	$REVU_2$	It hasn't exceeded its regulatory lifetime					
3	$REVU_3$	It hasn't exceeded its regulatory lifetime					
4	$REVU_4$	It hasn't exceeded its regulatory lifetime					
5	ROM_5	30,560	30,560	30,560	30,560	30,560	30,560
	μ_5	0.30	0.30	0.30	0.30	0.30	0.31
	$REVU_5$	9,168	9,168	9,168	9,168	9,168	9,474
6	$REVU_6$	It hasn't exceeded its regulatory lifetime					
Remuneration for the extension of the regulatory lifetime (€), REVU		**9,168**	**9,168**	**9,168**	**9,168**	**9,168**	**9,474**

Step 4: determination of the grid availability incentive (ID)
The grid availability incentive applies to the families of electricity transmission assets. These families of assets have a homogeneous treatment regarding the grid availability incentive because, given their functions and technical characteristics, they have a similar failure rate.

These families of electricity transmission assets are established in the annex of Circular 5/2019. In this fictional example, we have three different types of families of assets:

I. Overhead lines at 400 kV
II. Overhead lines at 220 kV
III. Transformer with primary at 400 kV

Substation bays and assets considered as unique facilities are not taken into account in the calculation of the grid availability incentive.

The grid availability incentive for an electricity transmission company can range between a minimum of -3.5% and a maximum of +2.5% of its O&M remuneration for that year.

Grid availability incentive

$$\mathbf{ID_{i,n}} = (\mathrm{CMax}_{i,n} \text{ or } \mathrm{CMin}_{i,n}) \cdot \frac{D^{i}_{n-2} - D^{min-i}_{n-2}}{D_{period\ target} - D^{min-i}_{n-2}}$$

$$\mathrm{CMax}_{i,n} \quad \text{if} \quad (D^{i}_{n-2} - D^{min-i}_{n-2}) > 0$$

$$\mathrm{CMin}_{i,n} \quad \text{if} \quad (D^{i}_{n-2} - D^{min-i}_{n-2}) < 0$$

$$\mathrm{CMax}_{i,n} = +2.5\% \cdot \mathrm{ROM}^{\,i}_{n}$$

$$\mathrm{CMin}_{i,n} = -3.5\% \cdot \mathrm{ROM}^{\,i}_{n}$$

$$D^{i}_{n-2} = \sum_{\forall F} \mathrm{IDF}^{i}_{n-2} \cdot k_{F,n-2}$$

$$\mathrm{IDF}^{i}_{n-2} = 100 - \mathrm{IIF}^{i}_{n-2}$$

$$\mathrm{IIF}^{i}_{n-2} = \frac{\sum_{\forall j\ of\ i \in F} t_j \cdot PN_j}{\sum_{\forall j\ of\ i \in F} T_j \cdot PN_j} \qquad k_{F,n-2} = \frac{\sum_{\forall j\ of\ i \in F} VOM_{F,j} \cdot UF_j}{\sum_{\forall j\ of\ i} VOM_j \cdot UF_j}$$

j	asset
i	transmission company
F	family of assets
n	year
VOM	O&M reference value
UF	number of assets
t	number of hours of interruption
T	yearly hours
PN	nominal power
ROM	O&M remuneration
D^{min-i}	minimum availability required to the company in order to not to be penalised
$D_{period\ target}$	availability target for the period

				2020	2021	2022	2023	2024	2025
Tj (h)				8,760	8,760	8,784	8,760	8,760	8,760
Family I (assets 1, 5)	UF_I	2	$t_{I,1}$ (h)	160	170	200	240	155	145
	$PN_{I,1}$	1000 MVA	$t_{I,5}$ (h)	200	190	300	260	145	135
	$PN_{I,5}$	1000 MVA	IIF_I	2.05%	2.05%	2.85%	2.85%	1.71%	1.60%
	VOM_I	30.560 €	k_I	70%	54%	54%	54%	54%	54%
			IDF_I	97.95%	97.95%	97.15%	97.15%	98.29%	98.40%
Family II (asset 4)	UF_{II}	1	t_{II} (h)		90	200	90	120	100
	PN_{II}	200 MVA	IIF_{II}		1.03%	2.28%	1.03%	1.37%	1.14%
	VOM_{II}	26.040 €	k_{II}		23%	23%	23%	23%	23%
			IDF_{II}		98.97%	97.72%	98.97%	98.63%	98.86%
Family III (asset 3)	UF_{III}	1	t_{III} (h)	150	100	200	120	120	150
	PN_{III}	200 MVA	$IIFI_{II}$	1.71%	1.14%	2.28%	1.37%	1.37%	1.71%
	VOM_{III}	26.200 €	k_{III}	30%	23%	23%	23%	23%	23%
			IDF_{III}	98.29%	98.86%	97.72%	98.63%	98.63%	98.29%
D				98.05%	98.39%	97.42%	97.91%	98.45%	98.48%
D_{min}*				97.50%	97.60%	97.80%	97.95%	97.91%	97.92%
$D_{period\ target}$				98.50%	98.50%	98.50%	98.50%	98.50%	98.50%
$D_{period\ target}$ - D_{min}**				1.00%	0.90%	0.70%	0.55%	0.59%	0.58%
CMax				4,309	5,656			5,656	5,656
CMin						-7,918	-7,918		
Grid availability incentive, ID (€)				**2,361**	**4,979**	**-4,341**	**-629**	**5,137**	**5,463**

* The minimum availability index required to the company for not being penalised is determined as the average of the availability index in the three years prior to year n-2. In consequence, for years 2023-2025 the minimum availability indexes have been calculated for the fictional example, but for years 2020-2022, we have assumed their values.
** According to article 15.7 of Circular 5/2019, ($D_{period\ target}$ - D_{min}) cannot take a value lower than 0.1.

Step 5: determination of the financial prudence penalty

A penalty on the remuneration is established for those companies who do not meet the recommended values of several economic and financial ratios. These ratios, and their recommended values, are defined in the Communication 1/2019[39] of CNMC. The maximum penalty is 1% of the remuneration.

Nevertheless, as established in the 3rd Additional Provision of Circular 5/2019, this penalty would not be applied until 2023, to let the companies adapt to the recommended values.

Financial prudence penalty

$$\mathbf{PPF_n} = -0.01 \cdot \mathrm{RA_n} \cdot (1 - \mathrm{IGR_n}) \qquad \text{if} \quad \mathrm{IGR_n} < 0.90$$

$$\mathrm{IGR} = 0.1 \cdot \mathrm{R1} + 0.05 \cdot \mathrm{R2} + 0.3 \cdot \mathrm{R3} + 0.2 \cdot \mathrm{R4} + 0.35 \cdot \mathrm{R5}$$

Ratios	Recommended values	R value for the IGR
$\text{Ratio 1} = \frac{\text{Net debt}}{\text{Net debt + Equity}}$	≤70%	R1 = 0 if Ratio 1 > 70% R1 = 1 if Ratio 1 ≤70%
$\text{Ratio 2} = \frac{\text{Funds arising from operations + Interest expenses}}{\text{Interest expenses}}$	≥5.0	R2 = 0 if Ratio 2 < 5.0 R2 = 1 if Ratio 2 ≥ 5.0
$\text{Ratio 3} = \frac{\text{Net debt}}{\text{RAB + Assets under construction}}$	≤70%	R3 = 0 if Ratio 3 > 70% R3 = 1 if Ratio 3 ≤70%
$\text{Ratio 4} = \frac{\text{Net debt}}{\text{EBITDA}}$	≤6.0	R4 = 0 if Ratio 4 > 6.0 R4 = 1 if Ratio 4 ≤ 6.0
$\text{Ratio 5} = \frac{\text{Net debt}}{\text{Funds arising from operation}}$	≤7.3	R5 = 0 if Ratio 5 > 7.3 R5 = 1 if Ratio 5 ≤ 7.3

PPF penalty value
n each year of the regulatory period
RA annual remuneration of the transmission agent
IGR general ratios index
R1 ratio 1
R2 ratio 2
R3 ratio 3
R4 ratio 4
R5 ratio 5

Net debt = Long-term debts + Long-term debts payable to group companies and associates + Short-term debts + Short-term debts payable to group companies and associates – Cash and cash equivalents
Funds arising from operations = Cash flow from operating activities – Changes in working capital – Capitalized expenses
EBITDA = Operating result + Depreciation + Impairments and gains/losses on disposal of non-current assets

[39] https://www.boe.es/diario_boe/txt.php?id=BOE-A-2019-15789

Financial statements	Items (in thousand euros)	2020	2021	2022	2023	2024	2025
Balance Sheet	Long-term debts	3,000	2,800	2,500	1,100	1,000	1,000
	Long-term debts payable to group companies and associates	2,200	2,100	2,100	2,000	2,000	2,000
	Short-term debts	1,500	700	500	500	500	200
	Short-term debts payable to group companies and associates	1,000	800	800	700	700	500
	Cash and cash equivalents	500	500	100	500	1,000	1,000
	Equity	2,500	2,000	2,200	2,200	2,100	2,100
	Assets under construction	4,781	0	0	0	0	0
Profit & Loss Account	Capitalized expenses	0	0	0	0	0	0
	Operating result	1,200	1,200	1,100	1,000	1,000	1,100
	Depreciation*	200	300	300	300	300	300
	Impairments and gains/losses on disposal of non-current assets*	30	35	40	45	50	40
Cash Flow Statement	Cash flow from operating activities	800	900	900	900	1,000	1,100
	Changes in working capital	-50	-45	-40	-40	-35	-35
	Interest expenditures*	300	250	200	110	100	80
Regulatory Asset Base (RAB)		9,251	13,801	13,450	13,099	12,749	12,398
Calculated magnitudes	Net debt	7,200	5,900	5,800	3,800	3,200	2,700
	Funds arising from operations	850	945	940	940	1,035	1,135
	EBITDA	1,430	1,535	1,440	1,345	1,350	1,440
Ratio 1	Result	74%	75%	73%	63%	60%	56%
	Recommended value	Maximum of 70%					
	Value for IGR	0	0	0	1	1	1
Ratio 2	Result	3.8	4.8	5.7	9.5	11.4	15.2
	Recommended value	Minimum of 5.0					
	Value for IGR	0	0	1	1	1	1
Ratio 3	Result	51%	43%	43%	29%	25%	22%
	Recommended value	Maximum of 70%					
	Value for IGR	1	1	1	1	1	1
Ratio 4	Result	5.0	3.8	4.0	2.8	2.4	1.9
	Recommended value	Maximum of 6.0					
	Value for IGR	1	1	1	1	1	1
Ratio 5	Result	8.5	6.2	6.2	4.0	3.1	2.4
	Recommended value	Maximum of 7.3					
	Value for IGR	0	1	1	1	1	1
IGR_n		0.50	0.85	0.90	1.00	1.00	1.00
RA_n (€)		970,526	1,361,301	1,332,406	1,316,543	1,302,734	1,283,790
Penalty, PPF_n (€)		**-4,853****	**-2,042****	**0****	**0**	**0**	**0**

* To make the calculation, these items change their sign.
**The penalty does not apply until 2023, according to the 3rd Additional Provision of Circular 5/2019.

Step 6: final calculation of the total remuneration

To determine the total remuneration of a transmission company we add the terms of investment and O&M remuneration, the remuneration for the extended regulatory lifetime of assets and the grid availability incentive. Then it is applied the remuneration adjustment if some assets and resources have been used in other activities, and the financial prudence penalty.

	2020	2021	2022	2023	2024	2025
Investment remuneration	786,634	1,120,912	1,101,336	1,081,761	1,062,186	1,042,611
O&M remuneration	172,363	226,242	226,242	226,242	226,242	226,242
Remuneration for exceeding assets regulatory lifetime	9,168	9,168	9,168	9,168	9,168	9,474
Grid availability incentive	2,361	4,979	-4,341	-629	5,137	5,463
Adjustment due to the use of assets and resources in other activities	In this example we assume that all the assets are only used in the electricity transmission activity, so we do not have to make any adjustment.					
Financial prudence penalty	n.a.	n.a.	n.a.	0	0	0
Total remuneration (€)	**970,526**	**1,361,301**	**1,332,406**	**1,316,543**	**1,302,734**	**1,283,790**

n.a.: not applicable

Annex 5.28 Case Study – Sweden

Electricity network regulation, regulatory period 2020–2023

General information

Before the regulatory period, Swedish NRA Ei determines revenue caps, partly based on forecasts, for every electricity network operator, normally for four-year periods, which is presented as a total for the entire customer collective of that operator. For details see Formula 1. After the regulatory period, Ei updates the revenue caps and replace the forecasts with the actual outcome. After the regulatory period, an adjustment of the revenue caps is also made by an annual supplement or deduction and also taking quality into account based on the way the network companies have been operating and to what extent the operation is compatible with or contributing to an efficient utilisation of the network. Formula 2 presents the calculation of the revenue caps after the regulatory period.

> ***Formula 1 =*** Capital costs based on opening capital base and projected investments and disposals + controllable costs (normally based on four-year historical costs), deducted for general and individual efficiency requirements + Non-controllable costs based on forecast data.
> ***Formula 2 =*** Capital cost based on opening capital base and actual investment and disposals + controllable costs (normally based on four-year historical costs, deducted for general and individual efficiency requirements) + Non-controllable costs based on actual data + supplement/deduction according to quality in the way the network companies have been operating and to what extent the operation is compatible with or contributing to an efficient utilisation of the network.

The differences in the price situation is also handled after the period. The practical handling of the indexing is presented in the section below.

The revenue cap that is set before the regulatory period is determined by an amount for the whole regulatory period of four years. In the decision it is clarified that the revenue cap after the regulatory period must be adjusted for every year with different indexes. The use of the indexes for cost and revenues should be considered to be limited so it is only used where it is directly stated in the legislation. The legislation states that for the factor price index for buildings, the construction cost trend is to be used for the capital base and the factor price index for electricity network companies, sub-index operation and maintenance costs, controllable for the controllable costs. The non-controllable costs will be determined based on the actual data for each year at each year's price level. These will also be deducted annually against the network companies' revenue when the final revenue cap is being compared to the revenues. Regarding the supplement or deduction according to quality in the way the network companies have been operating and to what extent the operation is compatible with or contributing to an efficient utilisation of the network, this is given in each year's price level. The price level management is only required in the part that refers to quality in the way the network companies conduct network operations as it is based on an established interruption cost estimate. This valuation is calculated to each year's price level with the consumer price index.

2. About capital base and cost of capital

2.1 Capital cost calculation method and valuation methods

The method that is used to calculate capital costs for electricity network companies' assets is a real linear depreciation method. In order to calculate the capital cost based on this method requires that the network assets are given a replacement value that reflects what would be the cost to acquire and commission an entirely new asset today, including project planning, materials, certain labour and material costs, preparation, etc., which is reported in accordance with good accounting principles.

There are four valuation methods that companies can use to give an electricity network asset a present acquisition value. These methods are ranked, which means that the first method should be used, if it cannot be used, the second method should be used and so on. The methods according to the ranking are as follows: 1) Norm value, 2) Initial acquisition value, 3) Book value and 4) Other reasonable value. Note that enumeration is done depending on the method to real terms according to the factor price index for buildings, the construction cost trend mentioned in the above section.

2.2 Depreciation ratio

Depreciation ratios that electricity network assets have for the regulatory period 2020-2023 is given in the table 1 below.

Categories for electricity network assets	**Economical depreciation (years)**	**Maximal depreciation (years)**
Other groundworks and buildings, line concession	50	62
Other lines, line concession	50	62
Other lines, area concession	50	62
Other overhead lines, line concession	50	62
IT-system	10	12
Cable box	30	37
Lines with voltage from 220 kV or more, with exception for overhead lines, line concession	40	50
Overhead lines with voltage from 220 kV or more, line concession	60	75
Overhead lines, area concession	40	50
Groundworks and buildings with connection to a network with high voltage from 220 kV or more, line concession	40	50
Groundworks and buildings, area concession	50	62
Meter	10	12
Network station	40	50
Shunt reactor	40	50
Steering and control equipment	15	18
Switchgear without secondary appliances	40	50
Transformer	50	62

Table 23 – Regulatory depreciation ratio for electricity assets (Sweden)

2.3 Calculation formulas for capital costs (CAPEX)

If a fixed asset is younger than the economic depreciation period, the calculation is done as follows:

Depreciation + Return = CAPEX
Where
Depreciation = Real Nuance Value / Economic Depreciation Time
*Return = Real nuance value * ((Economic depreciation time – electricity network asset age) / Economic depreciation period) * Real calculation interest before tax*

If an electricity grid installation is older than the economic depreciation period but younger than the maximum depreciation period, the calculation is done as follows:

Depreciation + Return = CAPEX
Where
Depreciation = Real Nuance Value / Age of the electricity network
*Return = Real nuance value * ((Age of the electricity network asset - One year younger than the age of the network asset) / Age of the network) * Real calculation rate before tax*

Also note the following:

- If a change is made in the regulatory asset base (investment or disposals) at some point during the first half of the year, this change will first affect the regulatory asset base the next six months. For example, if an investment is made in 2020 H1, it will be added to the regulatory asset base 2020 H2. This means that on average there is a three-month delay for regulatory asset base changes.
- The first year the electricity network asset has in the capital base is 0, not 1. For example, when the economic depreciation period is 30 years, this will generate full capital cost during the years 0 to 29, which is then 30 years.

3. Information regarding the calculation of current impactable costs and efficiency requirements

The controllable costs are calculated on the basis of an average of the companies' controllable operating and maintenance costs of four years of historical data two years before the start of the regulatory period. For the regulatory period 2020 – 2023, the controllable costs correspond to the companies' historical costs for the years 2014 – 2017. In cases where a company is newly established or that its operating and maintenance costs during the regulatory period are assumed to deviate significantly from the historical data, the company's forecasts for this cost item can be used instead, which is then replaced with actual data after the period.

An annual deduction due to efficiency requirements is made to all companies' considerable operating and maintenance costs.

For local area network companies, the annual efficiency requirements are individually designed for the local area network companies and mean that companies that conduct their operations less efficiently than other comparable electricity network companies are assigned a higher efficiency requirement. The minimum level that the claim can amount to is 1 percent and the highest level of the claim meant an annual reduction of 1.82 percent of the controllable costs. In summary, this implies that Ei, when determining the efficiency requirement, ensures that it is based on the Data Envelopment Analysis (DEA) method, which is based on comparisons between the local area network companies' performances. Each network company receives an individual requirement based on how its performance relates to the other grid companies. By comparing the companies to each other, a competitive pressure is simulated where the companies are given incentives to reduce their costs in relation to their competitors. The most efficient companies are assigned a requirement that reflects the industry's average productivity growth, which means that they must reduce their impact costs annually by 1 percent. The less efficient companies have a higher individual requirement to catch up with the efficient companies. If a company can increase productivity more than the set requirement, they may retain the difference in full.

The model that is constructed consists of two cost variables that constitute the resource consumption, controllable costs (OPEX) and capital costs (CAPEX), and five production variables: delivered energy distributed on high and low voltage, the number of subscriptions, the number of network stations and the highest value of subscribed and withdrawn power to overlying networks.

In the calculation, we also clear away non-comparable network companies according to set criteria for super-efficiency.

$Effi > q$ (75) + 2 $*$ [q (75) - q (25)], where:

$Effi$ = the measure of efficiency for companies in which is obtained by driving with super efficiency.

q (75) = the efficiency of the third quartile for all companies. q (25) = the efficiency of the first quartile for all companies.

An observation should thus be regarded as not comparable with the others if the measure of efficiency exceeds the sum of the third quartile and the difference between the first and third quartiles multiplied by 2.

As we move from potential to efficiency requirements, we have also built in a number of “filters”. These "filters" are as follows:

- The time to realise the full potential is set at eight years, that is, two regulatory periods;
- The realisation is shared with customers, i.e. 50-50;
- The highest level of efficiency potential is limited to 30 percent; and
- The lowest level of efficiency requirements is 1 percent per year.

No benchmarking is used for the regional distribution companies and transmission companies, but these receive the lowest annual requirement of one percent.

The requirements described above are applied only to the companies’ current controllable costs as we consider that current legislation prevents us from applying it on the additional cost items. However, in early 2020, a bill was submitted to the Swedish government where it would be possible to apply the requirement to all costs. They can begin to apply at the earliest the next regulatory period, 2024 – 2027.

4. Information on supplementary decisions for the next regulatory period due to deviation between final revenue caps after the period and revenues

If it turns out that the companies’ total revenues from network operations during the regulatory period 2020 – 2023 deviate from the established revenue cap for the same period, the revenue cap for the next period 2024 – 2027 shall decrease or increase by the differing amount. In addition, if a company's total revenue from the network operations during the regulatory period 2020 - 2023 exceeds the established revenue cap by more than 5 percent for the same period, an overcharging supplement will be added.