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CEER Report on Regulatory Frameworks for European Energy Networks 2021

Annex 5

Case studies of single regulatory regimes

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Annex 5.1 Case study – Austria

This section constitutes a short case study about the regulatory regime that applies to electricity distribution system operators (DSOs) in Austria during the fourth regulatory period (RP) and is based on the document "*Electricity Distribution System Operators 1 January 2019 – 31 December 2023 Regulatory Regime for the Fourth Regulatory Period*".[1] For further details and all references, please refer to the mentioned document.

Regulation of grid charges[2] can be based on annual cost audits, but this means a lot of 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. E-Control (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 that 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 an RP, 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 RP. 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 RP 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 a five-year period.

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 year of annual financial data available. For the fourth RP, 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] See https://www.e-control.at/en/web/guest/marktteilnehmer/strom/netzentgelte.
[2] This section uses the terms 'tariffs', 'charges' and 'rates' synonymously.

Worked example

Suppose that a specific DSO's allowed cost base for 2016 amounts to €600,000 of operational expenditure (OPEX) and €100,000 of non-controllable costs. Furthermore, assume that this operator's depreciation in 2019 is €100,000, the 2019 book value of its regulatory asset base (RAB) until 2016 is €1,000,000, the 2019 book value of investments from 2017 and 2018 is €150,000, and the 2019 book value of investments from 2019 is €100,000.

The regulatory authority calculates the allowed OPEX[3] by applying the network operator price index (NPI) and the general productivity growth rate (X_{gen}) of 0.95% pa 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.

$$Baseline\ OPEX\ 2018 = 504{,}908 = (600{,}000 - 100{,}000) * (1 + 1.614\%) * (1 + 1.293\%) * (1 - 0.95\%)^2.$$

The allowed OPEX 2018 constitutes the baseline for the present RP. 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:

$$\mathrm{ZV} = 1 - (1 - 0.95\%) * \sqrt[7.5]{\mathrm{ES}_{2018}}$$

where ES_{2018} designates the individual (weighted) efficiency score. This efficiency score is derived from a benchmarking procedure that comprises two methods (data envelope analysis (DEA) and modified ordinary least squares (MOLS)), two total expenditure (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%
100%	0.950%

Efficiency scores and overall targets (Austria)

Assuming an efficiency score of 90%, the OPEX[4] during the RP is calculated as follows:

$$OPEX\ 2019 = 501{,}857 = 504{,}908 * (1 + 1.769\%) * (1 - 2.332\%)$$
$$OPEX\ 2020 = 501{,}501 = 501{,}857 * (1 + 2.315\%) * (1 - 2.332\%)$$
$$OPEX\ 2021 = 501{,}527 = 501{,}501 * (1 + 2.393\%) * (1 - 2.332\%).$$

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

Capital expenditure (CAPEX) is tracked and compensated as it arises. Roughly speaking, CAPEX consists of depreciation and the cost of capital (opportunity cost) for the RAB. The

[3] $Baseline\ OPEX_{2018}^{Allowed} = (OPEX_{2016} - non\text{-}controllable\ costs_{2016}) * \prod_{t=2017}^{2018}\left[(1 + \Delta network\ operator\ price\ index_t) * \left(1 - X_{gen_{4th\ period}}\right)\right].$

[4] $OPEX_t^{Basis\ for\ charges} = OPEX_{t-1} * (1 + \Delta network\ operator\ price\ index_t) * (1 - overall\ efficiency\ target_{4th\ period}).$

regulatory authority introduced the concept of an individual weighted average cost of capital (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 RAB. If a company is more/less efficient than the average, its WACC is adjusted by a maximum of ± 0.5%. To ensure that the RAB of Austrian electricity DSOs 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:

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

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 RPs, the regulatory authority has to assume the same (average) efficiency for all investments. For investments from 2019 onwards, 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 book values from the year 2019 (see above), we arrive at the following calculation for the CAPEX to be included in 2021 grid charges:

$$CAPEX\ 2021 = 160{,}520 = 100{,}000 + 1{,}000{,}000 * 4.80\% + 150{,}000 * 4.88\% + 100{,}000 * 5.20\%.$$ [5]

The present incentive regulation system implies that the allowed OPEX is decoupled and may thereby diverge from actual OPEX. A new audit, based on which allowed OPEX is determined anew, normally only occurs before the outset of a new RP. However, the scope of the operators' mandate (number of consumers to be connected, etc.) evolves during the course of an RP, 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 RP. 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 (lag of t-2). For instance, both the 2021 expansion factor and RAB rely on data from 2019 (see above), but it can be safely assumed that OPEX and CAPEX are not the same in 2021 as they were two years earlier. The same is true for the non-controllable costs. This systemic time lag could deter companies from investing because they only recover their costs two years later, when new investments are included as part of direct CAPEX compensation and the parameters for the operating cost factor are updated. This means that

[5] $Direct\ CAPEX\ compensation_{2021} = Depreciation_{2019} + RAB^{2019}_{Assets\ up\ to\ 2016} * WACC\ individual + RAB^{2019}_{Assets\ from\ 2017} * 4.88\% + RAB^{2019}_{Assets\ from\ 2019} * 5.20\%.$

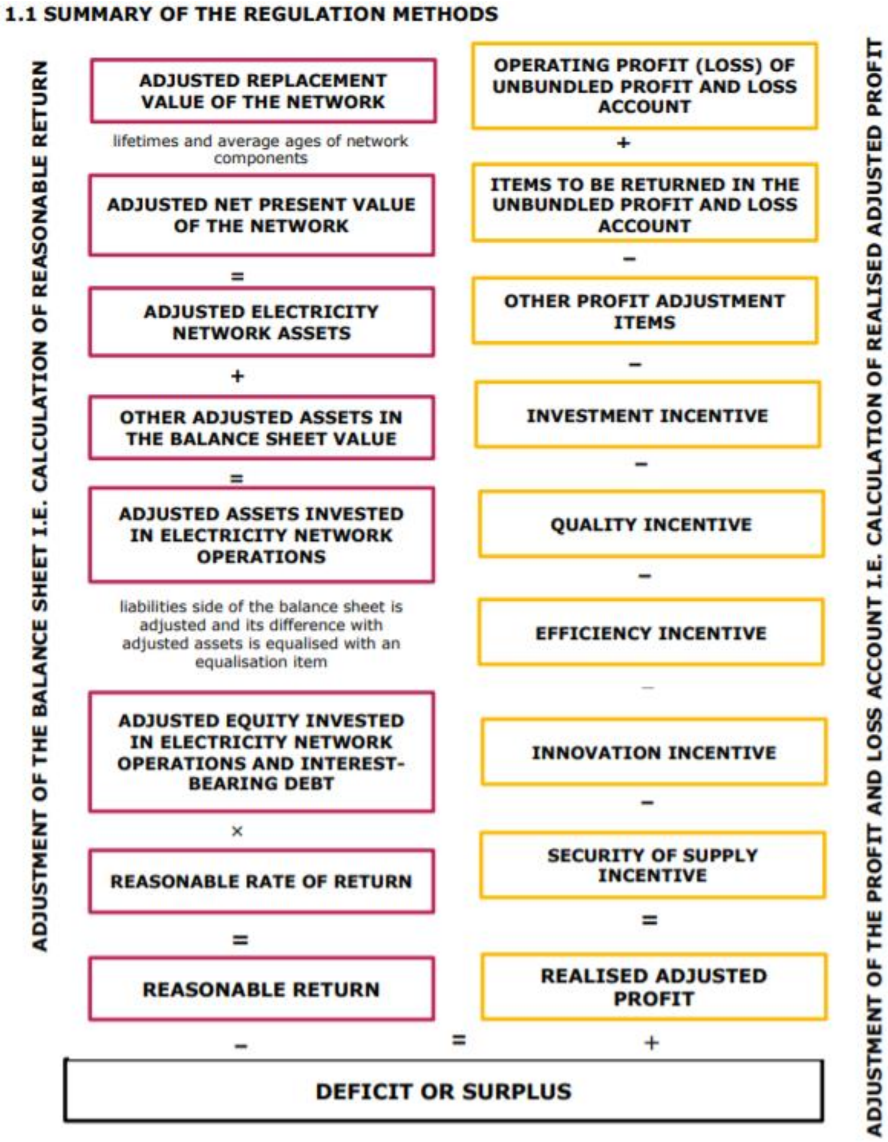
companies would have to pre-finance these investments, meaning they are exposed to a certain interest rate and liquidity risk. Vice versa, savings are not passed on immediately either, creating elevated charges for customers (at least for some time). The two-year time lag could result in rates that are 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 the latter becomes 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 5.7 Case study – Finland

This section describes a simplified case study about the regulatory regime and methodology for setting allowed revenues for electricity DSOs in Finland for the fifth RP (2020-23). The regulatory framework and principles applied are explained in more detail in the regulation methods document,[6] which can be found on the Energy Authority's webpage. The Energy Authority (the Finnish NRA) applies slightly divergent methodologies when setting the revenue cap for transmission system operators (TSOs) and DSOs 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 network operations is reviewed and reasonable return calculated on it, and on the other hand, the adjusted operating profit of network operations is reviewed.



Regulation methods during regulatory periods 2016-19 and 2020-23 (Finland)

[6] See 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 basis of the calculation of reasonable return, i.e. the revenue cap. The Energy Authority determines a reasonable return for each DSO annually, 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 is adjusted to correspond with their actual net present value (NPV). Hence, the revenue cap is calculated based on the adjusted NPV 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 multiplying them by component-specific unit prices (according to a pre-determined unit price catalogue). In turn, the adjusted NPV 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. 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 (RoR, WACC %). The DSO receives reasonable return on adjusted equity and interest-bearing debt, but 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, the reasonable cost of financial assets is deducted as profit adjustment items. The impact of incentives is also 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. A positive value resulting from the subtraction means a surplus and a negative value means a deficit.

At the end of the RP, the DSO's realised adjusted profits from different years are added together and deducted from the sum of reasonable returns from the corresponding years. A surplus will be compensated back to customers via lower distribution tariffs in the next RP. If the realised adjusted profit during the RP 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 RP in question.

Incentive mechanisms

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 that are based on a study commissioned by the Energy Authority.

In the fifth RP (2020-23), 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 (MV) and high-voltage (HV) distribution networks when determining the outage costs. The DSO's average realised regulatory outage costs for the two previous RPs (2012-19) 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 a cost-effective manner. The incentive is targeted to the controllable OPEX. The incentive steers DSOs to effective day-to-day operations and encourages them to invest in a way that will lower OPEX.

The incentive is based on the DSO's reasonable controllable OPEX that is 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 OPEX 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 OPEX from the reference level of efficiency costs for the year in question. In the fourth RP (2015-19) the Energy Authority applied a transition period for the improvement of efficiency, during which the DSOs must reach an efficient cost level. However, in the fifth RP (2020-23), there is no more transition period left and the DSO's realised controllable OPEX is compared directly with the level of efficient OPEX 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 the impact of the 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 (R&D) 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 RP is treated as reasonable R&D 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 (2016-19) and fifth (2020-23) RPs 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 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 NPV 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 residual NPVs resulting from early replacement investments carried out 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 DSOs. 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		
NPV 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**

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 €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 RoR (WACC %). We need to determine the applicable WACC % that consists of the reasonable cost of equity, reasonable cost of debt and assumed optimal capital structure. In the determination of the reasonable RoR we shall use the parameter values that 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%

Parameters (Finland)

Where:

- Reasonable cost of equity is $C_E = R_r + \beta_{equity} * (R_m - R_r) + L$;
- C_E = 1.45% + 0.828 * 5.0% + 0.6% = 6.19%;
- Reasonable cost of debt is $C_D = R_r + DP$;
- C_D = 1.45% + 1.26% = 2.71%;
- Reasonable RoR is $WACC_{pre-tax} = \frac{C_E * 0.60}{(1-yvk)} + C_D * 0.40$; and
- $WACC_{pre-tax} = \frac{6.19\% * 0.60}{(1-20\%)} + 2.17\% * 0.40 = 5.73\%$.

Now when the reasonable RoR 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	**4,011**	**4,581**

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 multiplying by the reasonable RoR.

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**

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, €4,500 t for DSO A and €4,000 t for DSO B. After this the reasonable costs of financial assets are deducted from the operating profit, €100 t for DSO A and €70 t for DSO

B. 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 a 20-year depreciation period and the value of network assets, calculated with standard unit prices, 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. The planned depreciations from the 20-year depreciation period, calculated according to the unbundled balance sheet, were returned to the adjusted profit earlier, €4,500 t for DSO A and €4,000 t for DSO B. Now from the effect of the 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 profit is 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 DSOs are €500 t and therefore below the reference levels. The impact of the 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 the DSO's quality bonus is limited to 15% of 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

Assume that DSO A's reasonable operational costs as a result of a national efficiency benchmarking (efficiency frontier) are €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 are €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, the incentive effect is €3,000 t - €4,000 t = -€1,000 t. As DSO B's reasonable return was set to €4,581 t, so the calculated impact of the efficiency incentive exceeds the 20% threshold level set to the incentive. In this case the DSO's efficiency bonus is limited to 20% of 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 residual NPV from early replacement investments worth €300 t and reasonable costs of maintenance and contingency measures worth €200 t, the effect of the incentive totalling €500 t. DSO B has made acceptable write-downs of residual NPV from early replacement investments worth €300 t, but no maintenance measures, so 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**

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 the RP 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 a cumulative surplus transferring to the next period, it must be equalised during the next RP by lowering distribution tariffs. If the DSO in turn has a 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 DSO.

Introduction

The electricity and gas network operators in Germany at the 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 RP, 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 2021 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 DSOs. 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:

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

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 RP. Controllable costs (C_c) are distributed across the individual years of an RP 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.

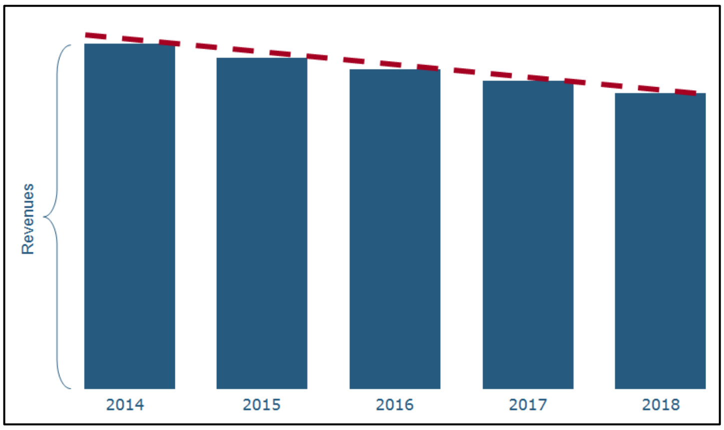
The costs incurred in the base year are requested from the network operators and reviewed. First, the permanently non-controllable costs are deducted from the reviewed overall costs. These costs are set by way of existing definitions and can be directly transferred to the revenues. These include, for 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[7]-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 CAPEX (based on depreciation and lower interest amounts) is deducted from both the temporarily non-controllable costs and the controllable costs.

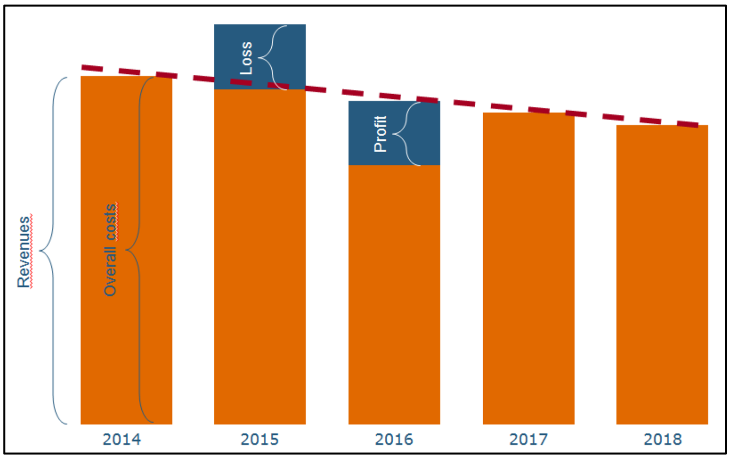
Since the inefficiencies are to be removed uniformly over the course of one RP, each year an increasing reduction factor $(1 - D_t)$ is applied to the controllable costs. This gives the revenue cap a stepped trajectory, as illustrated in Figure 2:



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 CAPEX, the determined temporarily non-controllable and controllable costs from the base year are applied to the entire RP; 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 RP, as Figure 3 illustrates:



Revenue cap enables additional profits (Germany)

[7] TOTEX = sum of OPEX and 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 their revenues, uniformly distributed over the duration of the RP.

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 CAPEX, 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 CAPEX mark-up, network operators report in the previous year on the amount of their planned investments in necessary network assets. This CAPEX is made up of the imputed depreciations, imputed return on equity, imputed trade tax as well as the incurred interest on debt.

The quality regulation calculation returns 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 recorded in 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 DSOs. 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[8]	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
CPI in the base year	100	100

Framework conditions (Germany)

[8] Based on calculated costs instead of depreciations defined by the 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:

- Review of overall costs and the different cost categories;
- Application of the efficiency score;
- Determination of other revenue components; and
- 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 and trade tax, and subtract the cost-reducing revenues from this amount. After that we have the overall DSO's overall costs, 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[9]	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[10]	1,000	800
10. ∑(Temporary non-)Controllable costs[11,12]	1,650	1,200

Review of cost categories (Germany)

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 RP. 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[13]	20%	20%
16. Controllable costs in the first year of the RP (14. * (1 – 15.)	0	96

Application of the efficiency score (Germany)

Since DSO A has been given an efficiency score of 100%, it does not have any inefficiencies to remove over the RP. The controllable costs are therefore zero, 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 RP. The controllable costs are therefore 120 in total; for the first year of the RP

[9] Return on equity is calculated based on the costs of tangible assets financed by equity, multiplied by the RoR on equity of 6.91%.
[10] Defined by cost catalogue.
[11] Separated into a controllable and temporally non-controllable part by using the determined efficiency score.
[12] Parts of positions No. 1., 2. and 7. are included at No. 9.
[13] Value at the first year of the RP.

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 CPI at the base year was 100, and 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 in the first year of the RP, DSO A gets a CAPEX mark-up of 100 and DSO B a mark-up of 200. As a result of the quality regulation, we assume a value of 50 for DSO A, and a value of -100 for DSO B. The volatile costs of the base year have a value of 200 for DSO A and 100 for DSO B. For the first year of the RP 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 RPs are assumed to be zero.

	DSO A	DSO B
17. Efficiency bonus	0	0
18. CPI in the base year	100	100
19. CPI in first year of regulation	101	101
20. Development of prices (19./18.)	1.01	1.01
21. Productivity factor[14]	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. CAPEX 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

Determination of other revenue components (Germany)

Step 4: Final calculation of the revenue cap

For the determination of the revenue cap, the DSOs in principle apply the following formula:
$RC_t = C_{pnc,t} + \left(C_{tnc,t} + (1 - D_t) * C_{c,t} + \frac{B_0}{T}\right) * \left(\frac{CPI_t}{CPI_0} - PF_t\right) + CM_t + Q_t + (VC_t - VC_0) + A_t.$
Therefore, we get a revenue cap for the first year of the RP 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.

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

If the permanently non-controllable costs, CPI, CAPEX mark-up, quality element, volatile costs or balance of the regulatory account change in the course of the RP, the revenue cap is adjusted accordingly.

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

[14] Assumed fictional value.

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.

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 5.11 Case study – Greece

Methodologies regarding allowed revenue for TSOs and DSOs in the electricity and gas sectors converge on basic principles, however some differences remain, and the harmonisation process is in progress.

This section provides a short case study regarding the regulatory regime that applies to the independent power transmission system operator (ADMIE SA) during the second RP, 2018-21.[15]

The Regulatory Authority for Energy (RAE) decides on the allowed revenue (AR) and the required revenue (RR) of ADMIE for a four-year RP, based on the TSO's proposal and approved ten-year network development plan (TYNDP, investment plan).

The calculation of AR is based on reasonable and efficient costs (OPEX and CAPEX) and the return on the capital employed (RAB). Moreover, an incentive scheme for OPEX is applied, which allows the operator to earn an additional profit, if it reduces its OPEX.

The RR, which is the revenue that is recovered through the Use of System (UoS) charges, is calculated based on the AR and any required adjustments.

Below we present a short overview of the calculation of the AR and RR of ADMIE (electricity TSO) for the fourth year of the RP 2018-21.

A Allowed revenue 2021 – electricity TSO

The AR of the electricity TSO is calculated in real terms before the beginning of the RP and for each year of the RP as $AR = O + Dep + R$, where:

- O is estimated annual operating expenses;
- Dep is the annual depreciation on the tangible and intangible assets; and
- R is return on the capital employed (RAB).

A.1 Operating expenditure (OPEX)

OPEX includes the reasonable expenses of the electricity TSO, for the operation and maintenance of the national transmission system (the Greek abbreviation 'ESMIE' is used hereinafter) and divided into the following categories which are reported separately: a) payroll, b) third party payments, c) materials and consumables, and d) other expenses. Financing costs, taxes on operator's profits, and provisions (such as provisions for bad debts or for disputed legal cases) are not included.

The total approved OPEX for 2021 is €79 million, of which €66 million is payroll-related expenses.

A.1.1 Efficiency Incentive

During the RP 2018-21, OPEX is not subject to any ex post adjustment or settlement within the RP. This creates an incentive for the operator to reduce its OPEX allowance and become more efficient. It should be noted that in the amended methodology that will be in force from 2022 onwards (495/2021), the efficiency incentive has been further improved to include a sharing mechanism for controllable OPEX (the expenditure saving will be shared between the electricity TSO and network users). Moreover, under the amended methodology, OPEX

[15] According to the "Methodology for Calculating the Required Revenue of the Hellenic Transmission System Operator" (Decision 340/2014), which was amended by RAE Decision 495/2021 in order to be harmonised with other operators in Greece. The new methodology is going to be applied from 2022 onwards.

is divided into controllable and uncontrollable expenses, depending on the operator's ability to control and set the values of each OPEX category. Uncontrollable expenses include taxes, fees, and levies. Controllable expenses include categories such as payroll, third-party payments, materials and consumables, and other expenses.

On controllable expenses, an incentive mechanism is applied to incentivise the electricity TSO to improve its efficiency. This mechanism is applied to savings on controllable expenses (actual), compared to forecasted controllable expenses, and the relative sharing factor ranges between 40% and 70% in favour of the operator (the value of this factor is determined in the regulatory decision for transmission).

A.2 Depreciation of assets

Depreciation is calculated for each year of the RP, based on the regulatory asset register, following a straight-line method and considering the economic instead of accounting life. No revaluations are taken into account. Depreciation is calculated for all assets expected to be in use during each year of the RP, while assets under construction (WIP) are remunerated only for return. Assets funded by third parties or contributions are excluded from the RAB and thus from calculation of depreciation.

The total depreciation amount for 2021 based on the regulatory asset register is €77 million.

A.3 Return on RAB

The return on the capital employed is calculated based on:

- The estimated value of the (RAB) of the year; and
- The approved pre-tax RoR (r) / WACC.

A3.1 Regulatory Asset Base (RAB)

The RAB includes the estimated capital employed for the regulated activity, estimated for each year of the RP as follows:

- (+) Undepreciated value of assets according to the regulatory asset register;
- (+) WIP[16]/new investments;
- (+) Working capital;
- (-) Disposals; and
- (-) Grants and contributions from third parties.

The RAB for 2021 was estimated to be €2 billion, of which working capital was €77 million and grants and contributions from third parties were €227 million.

From 2009 onwards no revaluation has been considered for regulatory purposes.

A.3.2 Weighted Average Cost of Capital (WACC)

The WACC is calculated as a RoR for the RAB. For the electricity TSO, the WACC is estimated in real terms (pre-tax)[17] as $WACC_{real} = \frac{1+WACC_{nominal}}{1+i} - 1$, where:

- i is inflation; and
- $WACC_{nominal}$ is given by the equation below.

[16] Under the amended methodology for the electricity TSO, projects of major importance during their construction period are included in the WIP, while until 2021 they are included in the RAB when they are electrified.

[17] For the electricity DSO, gas TSO and gas DSOs, a nominal, pre-tax WACC is used. The methodology for the electricity TSO was amended in order to be harmonised with the methodologies applied for the other electricity and gas operators; therefore, for the RP 2022-25 a nominal pre-tax WACC will be applied also for the electricity TSO.

$WACC_{nominal} = g * r_d + (1 - g) * r_e/(t - 1)$, where:

- g is the gearing ratio;[18]
- r_d is the cost of debt;[19]
- $r_e = r_f + \beta_{equity} * MPR + CRP$ is the cost of equity (post-tax, nominal), where β_{equity} is equity beta, MPR is the market risk premium and CRP is the country risk premium; and
- t is the corporate tax rate.

The WACC in real terms (pre-tax) is 6.3%. The values of the parameters that are used for the calculation of WACC are presented in Table 13.

Weighted average cost of capital 2021	
Risk-free rate (r_f)	0.7%
Market risk premium (MRP)	5.0%
Gearing ratio (g)	40.30%
Beta equity (β_{equity})	0.72
Country risk premium (CRP)[20]	1.5%
Cost of equity pre-tax ($r_{e,post-tax}$)	5.8%
Tax rate (t)	29%
Cost of equity pre-tax ($r_{e,pre-tax}$)	8.2%
Cost of debt (r_d)	5.13%
WACC, pre-tax, nominal ($\mathbf{WACC_{nominal}}$)	**6.95%**
Inflation[21] (i)	0.6%
WACC, pre-tax, real ($\mathbf{WACC_{real}}$)	**6.3%**

Approved weighted cost of capital for the year 2021 (Greece)

The analytic expression of the nominal WACC is $WACC_{nominal} = g * r_d + (1 - g) * (r_f + \beta_{equity} * MPR * CRP)/(t - 1)$.

A.3.3 WACC Premium

For projects of major importance that are included in the approved TYNDP, a premium RoR can be provided, in addition to the base WACC. The percentage of this premium varies between 1% and 2.5%. The WACC premium is provided as soon as the project is electrified and up to the 12th year from the planned year of electrification, according to the approved TYNDP in which the project is characterised as a project of major importance.

In the amended methodology both the range and the duration of the WACC premium have been modified. More precisely, according to the new methodology, the WACC premium varies between 0 and 2% and it can be provided for a period of four to seven years, starting from the projected year of commercial operation according the approved TYNDP. In case of unjustified delays in the project's timeline, this extra WACC premium can be reduced.

A.4 Allowed revenue 2021

Based on the above, the AR for 2021 is summarised in the following table.

[18] Until 2021, a value close to the actual gearing was considered. The new methodology introduces notional gearing as a principle.
[19] Until 2021, an estimated cost of debt was taken into account, according to actual (previous years) financing cost. According to the new methodology (Decision 495/2021), the estimated cost of debt is equal to a risk-free rate (which may differ from that used for the cost of equity) plus a debt premium.
[20] Due to specific country conditions, an extra premium (country risk premium) is added to the capital asset pricing model (CAPM).
[21] Estimated in 2018.

Allowed revenue of the electricity TSO 2021	
OPEX	79,066,000
Depreciation	77,063,000
RAB	2,059,771,000
WACC (real, pre-tax)	6.3%
Return on RAB (R)	129,766,000
Allowed revenue (AR)	**285,895,000**

Allowed revenue of the electricity TSO for the year 2021 (in €) (Greece)

Required revenue 2021 – electricity TSO

The RR is recovered through the system usage charges (capacity and commodity) by all customers connected to ESMIE and to the distribution network. The RR is calculated based on the AR, considering certain adjustments (parameters) as $RR = AR \pm K \pm \Pi_1 \pm \Pi_2 - \Pi_3 \pm \Pi_4 - \Pi_5$, where:

- AR is the allowed revenue of the electricity TSO;
- K is the cost of projects of ESMIE that are funded by third parties;
- Π_1 is the settlement amount due to under/over recovery of RR in previous years;
- Π_2 is the settlement amount due to under/over investment in previous years;
- Π_3 is the revenues from interconnection rights (auctions);
- Π_4 is the expenses/revenues from participation in the inter-TSO compensation mechanism (ITC mechanism) between TSOs; and
- Π_5 is the revenues from other, regulated or non-regulated, activities.

Based on the above, the RR of the electricity TSO for the fourth year of the RP 2018-21 is €211,596,945. The values of the parameters that constitute the RR are summarised in the following table.

amounts in €	2021
Allowed revenue (AR)	285,895,000
Cost of projects funded by third parties (K)	0
Underinvestment (+) / overinvestment (-) (Π_1)	142,810
Clearings due to underinvestment / overinvestment in previous years (Π_2)	-6,141,261
Revenues from interconnection rights (Π_3)	-66,179,594
Revenues from participation in ITC mechanism (Π_4)	1,906,410
Income from non-regulated activities (Π_5)	-9,699,060
OPEX ARIADNI / RSC	*5,672,640*
Required revenue ESMIE 2021 (RR)	**211,596,945**

Required revenue parameters (Greece)

Annex 5.16 Case study – Latvia

The current natural gas transmission system tariff calculation methodology for the gas TSO was implemented in 2019. This introduced major changes in the tariff calculation methodology related to the regulatory regime – a move to a revenue cap approach, the introduction of efficiency incentives, and the inclusion of requirements for the entry-exit system regulations covering several Member States with several natural gas TSOs.

The change in the regulatory regime was related to the strategic goal in the energy sector to gradually move to tariff setting by following the revenue cap approach. Prior to the changes in the methodology, the tariff setting approach was described as a hybrid approach, primarily based on a cost-plus approach. During 2019 and 2020, the same approach was introduced in the tariff calculation methodologies for electricity TSO and DSOs, the gas DSO and gas storage operator.

The revenue cap approach is characterised by a predictable and stable tariff, business-oriented corporate governance, and greater scope for incentive-based regulatory mechanisms. The revenue cap approach is one of the most common tariff-setting approaches for system operators in Europe.

Amendments to the methodology regarding the single natural gas transmission entry-exit system were an important precondition for the launch of the single entry-exit system (connecting Finland, Estonia and Latvia (FinEstLat)).

As a result of the establishment of the single natural gas transmission entry-exit system in FinEstLat, no transmission tariffs are applied to natural gas transportation between Finland, Estonia and Latvia from 2020. This means that a tariff is applied only once when the natural gas crosses the border of the single natural gas transmission entry-exit system. Furthermore, the tariff is the same at all entry points of the single natural gas transmission entry-exit system.

The establishment of the single natural gas transmission entry-exit system activates the operation of the regional natural gas market, strengthens Latvia's energy independence, including reducing the domination of the incumbent supplier JSC Gazprom in the region, promotes competition in the natural gas market, and facilitates more efficient use of the regional natural gas infrastructure, including the Inčukalns underground gas storage facility. This in turn results in more competitive natural gas prices and high-quality services, benefiting natural gas users.

Regulatory and tariff period

The tariff calculation methodology provides for the length of the RP. The tariff period shall be three gas years if the regulator has not decided on a different length of the RP or the tariff period until 15 January of the starting year of the RP or the tariff period.

If there is more than one tariff period within an RP, the allowed revenues shall remain unchanged during the RP unless there are changes in the costs of securing natural gas supply that are applied to a tariff period. Where there is more than one tariff period within an RP, the planned revenue within the tariff period is changed in accordance with revenue adjustment.

The planned revenue for a tariff period covers the costs of capacity booking to be included in the tariff calculation. The estimated revenue over the tariff period is determined by the total cost of the capacity booking service minus the amount of the capacity booking service costs to be reduced by the system operator (by improving the efficiency of the use of assets and other resources as well as operational efficiency) and minus the balance of revenues and costs relating to the ITC mechanism.

Determining allowed/target revenues

The planned revenue for a tariff period covers the costs of capacity booking to be included in the tariff calculation. Planned revenue for a tariff period is calculated according to the formula $Ie_{PSO} = I_{PSO} - I_{PSO\,ef} - ITC$, where:

- Ie_{PSO} is the planned revenue for a tariff period (EUR);
- I_{PSO} are the total costs of the capacity booking service (EUR);
- $I_{PSO\,ef}$ is the amount of the capacity booking service costs to be reduced by the system operator by improving the efficiency of the use of assets and other resources as well as operational efficiency (EUR); and
- ITC is the balance of revenues and costs relating to the inter-TSO compensations of TSOs of the single natural gas transmission entry-exit system that, in accordance with the inter-TSO compensation terms and conditions is attributed to the system operator (EUR).

The cost amount for providing the capacity booking service that the system operator must reduce (by improving the efficiency of the use of assets and other resources as well as operational efficiency) shall be calculated according to the formula $I_{PSO\,ef} = \left(I_{PSO} - Ie_{kor} - ITC - I_{sist} - I_{nod(st,nac)}\right) * K_{ef}$, where:

- Ie_{kor} is revenue adjustment attributed to the cross-border and national transmission systems (EUR);
- I_{sist} are the costs of securing natural gas supply (EUR);
- $I_{nod(st,nac)}$ are taxes applicable to the cross-border and national transmission systems (EUR); and
- K_{ef} is a cost efficiency coefficient.

To determine the cost level that the system operator must achieve until the beginning of the next RP, and that will be used in tariff calculations for next RP, a cost efficiency coefficient is applied to a part of the costs of the capacity booking service. The regulator determines the cost efficiency coefficient for the RP by observing comparable efficiency indicators from EU and Latvian energy TSOs as well as other objective indicators. While determining the efficiency coefficient, the regulator considers the system operator’s justified opinion regarding the efficiency coefficient level and its impact on the secure operation of the transmission system.

If the RP is longer than a year, the amount by which the system operator must reduce the costs of the capacity booking service (by improving the efficiency of the use of assets and other resources as well as operational efficiency) is equal for all tariff periods. Following a justified request from the system operator, the regulator may authorise the application of a different approach for allocating the total amount for which the system operator must reduce the costs of the capacity booking service to each tariff period within the RP.

The costs of the capacity booking service I_{PSO} included in the tariff calculation are formed of:

- The CAPEX of the cross-border and the national transmission systems;
- OPEX;
- Taxes applied to the cross-border and the national transmission systems; and
- Revenue adjustment attributed to the cross-border and the national transmission systems.

CAPEX

CAPEX consists of depreciation and return on capital, which is calculated by applying a RoR (WACC, determined by the regulator) to the value of the RAB.

Setting the RAB value

The RAB value of the transmission system consists of:
- The residual balance sheet value of the fixed assets, the intangible investments and inventories owned by the system operator on 1 January of the first year of RP (taken from the operator's financial statement); and
- The payments listed in the assets for participation in international transmission infrastructure projects and commitments arising from decisions on the allocation of investment costs, that have been taken in accordance with Regulation No. 347/2013 of the European Parliament and of the Council on guidelines for trans-European energy infrastructure and repealing Decision No. 1364/2006/EC and amending Regulations (EC) No. 713/2009, (EC) No. 714/2009 and (EC) No. 715/2009.

The RAB excludes financial investments, amounts receivable, securities, participating interest in capital, monetary instruments, the accumulated supplies of gas for sale as well as the value of a part of the fixed assets financed under the financial assistance or financial support of the local government, a foreign state, the EU, other international organisations and institutions.

Fixed assets acquired, financed by the users (via connection fees) are not included in the RAB value; the depreciation of these fixed assets is not covered by the tariffs and no return on capital is calculated for these assets.

Setting the WACC

The WACC is set yearly, and the system operator must apply it when calculating the new tariff proposal that is planned to come into effect in the respective year. However, the WACC stays the same during the RP.

Since 1 January 2020, a pre-tax real WACC is applied in the natural gas sector. Changes in the WACC calculation methodology were made in 2019. The main reason for the introduction of the real WACC was that the WACC calculation methodology is applied to different regulated sectors that have different approaches to revaluation of regulated assets. There was therefore a need to create equal conditions for sectors where companies mainly use the historic cost for regulated assets and sectors where companies perform asset revaluations regularly.

Depreciation

Depreciation of fixed assets and intangible investment is calculated in accordance with international accounting standards and the accounting policy adopted by the system operator. Depreciation of the gas TSO is calculated by the linear method. The typical asset life depends on the asset type: buildings 20-100 years, TSO infrastructure 40-60 years, and other assets/intangible assets three-30 years.

Taxes

The real estate tax is calculated only for assets included in the RAB in accordance with the laws and regulations. Corporate income tax is not included separately, as it is included in the return on capital, which is calculated using a pre-tax WACC.

OPEX

OPEX includes costs of:

- Natural gas transmission losses and ensuring technological processes of transmission system;
- Personnel;
- Repair and maintenance;
- Other economically justifiable activity of the transmission system; and
- Securing natural gas supply.

Natural gas transmission losses and ensuring technological processes

The costs of natural gas transmission losses and ensuring technological processes of the cross-border and national transmission systems are related to the difference between the volume of natural gas supplied to the transmission system and the natural gas withdrawn from the transmission system within a particular time period, which is formed by the losses of natural gas transmission and the consumption of natural gas for technological needs.

Personnel costs

Personnel costs of the cross-border and national transmission systems are calculated in accordance with the labour market conditions, Labour Law and the laws and regulations governing the field of social insurance.

Repair and maintenance costs

The costs of the current operating repairs of the cross-border and national transmission system assets and administration assets that are leased by the system operator and are in the accounting balance sheet thereof and performed by other merchants, shall be written off and recorded in the accounting period during which they have arisen. This position also includes financing costs of accumulated natural gas supplies according to the turnover cycle and applying the incurred interest rate.

The costs of maintaining natural gas supplies are estimated considering the necessary volume of natural gas supply considering the continuous provision of the capacity booking service and compliance with security of supply requirements. The incurred interest rate that is applied to the financial costs of maintaining accumulated natural gas supplies cannot exceed the six-month average variable interest rate for (new) short term loans (euro) (comparable to the volume of the accumulated supplies to be maintained) for non-financial institutions published by the Bank of Latvia. Capitalised repair costs, and costs concerning the development of new assets and financing costs of maintaining related natural gas supplies, are not included here.

Other costs of economic activity

Other costs of economic activity of the cross-border and national transmission systems are the costs related to the economic activity of the system operator, that are not recorded under other balance sheet cost items.

Securing natural gas supply

The costs of securing natural gas supply relate to the obligation of the system operator stipulated in the Cabinet of Ministers Regulation No. 312 to ensure necessary natural gas withdrawal capacity from the Inčukalns underground gas storage facility (UGS) during the energy crisis. These costs shall be included in the draft tariff in accordance with the actual, justified amount. These costs are to be recovered within two storage gas years starting from the moment the costs are incurred.

The joint natural gas transmission and storage system operator (Conexus Baltic Grid), in agreement with the Ministry of the Economy and Regulator, has determined that the most appropriate model for fulfilling the obligation laid down in Regulation No. 312 is an auction for storing and accessing the quantity of active natural gas in Inčukalns UGS. Conexus Baltic Grid has been conducting auctions annually during or prior to the injection season.

The costs of securing natural gas supply related to the obligation of the system operator stipulated in the Regulation No. 312 are one of the major cost elements of the natural gas TSO. The value of these costs is influenced by the price of natural gas, the price of future transactions, as well as the types of loss hedging available to natural gas suppliers at the time of the auction.

According to the tariff calculation methodology, the costs of securing natural gas supply are included in the operating costs of the national transmission system and are only considered when determining the charge for the use of the exit point for the supplying gas users in Latvia. Such a cost allocation principle was established in the assessment of the results of the costs of securing natural gas supply: the supply of natural gas during the energy crisis of Latvia is ensured and the required level of pressure is ensured in the natural gas transmission system. Given that the necessary pressure level in the natural gas transmission system is provided not only by the amount of natural gas stored in the Inčukalns UGS according to Regulation No. 312, but also by the amount of natural gas stored by the natural gas suppliers at the Inčukalns UGS, it can be concluded that the allocation of the costs should be based on the objective of the cost of securing natural gas supply — to provide a supply of natural gas to Latvia during the energy crisis.

ITC mechanism

In accordance with Article 10(3) of the network code on harmonised transmission tariff structures (NC TAR), to allow for the proper application of the same reference price methodology jointly, an effective ITC mechanism shall be established to prevent detrimental effects on the transmission services revenue of the TSOs involved and to avoid cross subsidisation between intra-system and cross-system network use.

The absence of internal commercial interconnection points and the possibility of applying the flat tariff at all FinEstLat single natural gas transmission entry-exit system entry points from other transmission entry-exit systems is one of the most significant principles of the FinEstLat single natural gas transmission entry-exit system.

In order to cover the reasonable costs incurred by the natural gas TSOs resulting from the provision of the natural gas transmission service in the FinEstLat single natural gas transmission entry-exit system, without any detrimental impact on the transmission service revenues of the TSOs involved, the TSOs of the FinEstLat single natural gas transmission entry-exit system entered into agreement on ITC terms and conditions in Finland, Estonia and Latvia. According to this agreement, the Latvian natural gas TSO and the other natural gas TSOs in the FinEstLat single natural gas transmission entry-exit system will receive from, or make payments to, the other TSOs of the FinEstLat single natural gas transmission entry-exit system.

In particular, the basic principles of the ITC system of the FinEstLat single natural gas transmission entry-exit system are:

- The revenue recovered from the tariffs of all entry points of the FinEstLat single natural

gas transmission entry-exit system is considered a single pool;
- The pooled revenue is shared between TSOs based on the share of natural gas delivered through the transmission system for domestic consumption in a particular country, including consumption for natural gas transmission losses and technological purposes in the total quantity of natural gas delivered through the natural gas transmission system for consumption in the FinEstLat single natural gas transmission entry-exit system. The distribution of pooled revenue is carried out monthly, using the previous year's corresponding national consumption shares in the total consumption of the FinEstLat single natural gas transmission entry-exit system;
- The variable costs incurred by the TSOs due to the ensuring of flows not dedicated for delivery to the specific market directly, is based on a regional flow scenario agreed between natural gas TSOs and estimates of compressor fuel costs incurred to facilitate the regional flow;
- For the purpose of compensation of eligible variable costs, the eligible variable costs shall be subtracted from the invoiced entry revenue of the natural gas TSO that incurred the eligible variable costs. Eligible variable costs to be compensated must be justified by appropriate invoices or calculations;
- At the end of the year, a reconciliation of the revenue recovered from the tariffs at the entry points of the FinEstLat single natural gas transmission entry-exit system is done. The reconciliation process shall result from a recalculation of the ITC entitlement shares attributable to the natural gas TSO based on actual data for the annual domestic natural gas consumption in Finland, Estonia and Latvia, and a reallocation of revenues based on the identified actual ITC entitlement share for each TSO. The estimated actual ITC entitlement share for each TSO shall be used for allocation of the following year’s pooled revenue;
- Calculation of ITC entitlement shares and annual entry revenue reconciliation shall be performed by the elected data administrator, which shall be one of the TSOs and shall rotate annually; and
- The role of the data administrator, unless agreed otherwise, shall be performed in the following order: Elering AS (Data Administrator’s obligations in 2020), Conexus Baltic Grid, the Finnish natural gas TSO.

There are the following exit points to other natural gas transmission entry-exit systems in the FinEstLat single natural gas transmission entry-exit system:
- Narva exit point (Estonia-Russia);
- Varska exit point (Estonia-Russia);
- Izborsk exit point (Estonia-Russia); and
- Kiemenai exit point (Latvia-Lithuania).

Forecasting of the entry capacity for the Latvian natural gas supply system was carried out accordance with sub-paragraph 2.7 of the tariff calculation methodology, which set out that the estimated average daily capacity at the entry point is equal to the average daily capacity used (kWh/d) at the entry point within the three previous calendar years. The forecasted capacity at Kiemenai exit point is 4,874 MWh/day/year, i.e. 6% of the exit capacity of the transmission system in Latvia, and less than 1% of the exit capacity of the FinEstLat single natural gas transmission entry-exit system.

The forecasted booked capacity at the Korneti exit point would be attributed to Izborsk exit point and would be less than 1% of the exit capacity of the FinEstLat single natural gas transmission entry-exit system. Having assessed the natural gas flows from 2017 to 2019, it is established that natural gas flows to Russia can only be observed during repair work in the Russian north-west natural gas transmission system. The negligible amount of forecasted booked capacity towards Russia is explained by the fact that repair work in 2020-22 is not intended and consequently the natural gas flows to Russia will be minimal.

In light of the above, it can be concluded that there will in principle be no natural gas transit in the FinEstLat single natural gas transmission entry-exit system during the period 2020 to 2022, and that the whole system will operate in order to meet domestic demand for natural gas. The ITC regime is therefore based on the allocation of revenue among natural gas TSOs based on domestic natural gas consumption of the country concerned, and it is considered that this shall not allow for cross-subsidisation between intra-system and cross-system network use.

The choice of the basic principle of the ITC regime is also linked to the envisaged activities of the TSOs of the FinEstLat single natural gas transmission entry-exit system for the management of natural gas flows – TSOs do not use physical (point-to-point) delivery, but use flow netting.

One of the features of the FinEstLat single natural gas transmission entry-exit system is the flat tariffs at all single natural gas transmission entry-exit system entry points, preventing discrimination of routes of supply and reducing the barriers for new market entrants. Due to the above, the changes in the natural gas suppliers' booking practice regarding the usage of the FinEstLat single natural gas transmission entry-exit system entry points are unpredictable. Taking into account the topology of the natural gas transmission systems within the FinEstLat single natural gas transmission entry-exit system, which effectively prevents circular natural gas transportation as a result of the change of the natural gas entry flows within the FinEstLat single natural gas transmission entry-exit system, a part of the currently less-used transmission system will be loaded with a view to relieving currently more-used parts of the transmission system.

It is expected that the launch of the FinEstLat single natural gas transmission entry-exit system will increase the number of natural gas trading transactions at the virtual trading point without any significant change in natural gas flows during the initial period.

Furthermore, it should be noted that the cooperation agreement between the natural gas TSOs necessary for the single Estonia-Latvia balancing zone to enter into operation assumes that both natural gas TSOs operate as a single system operator providing network users service and the technical cooperation.

If, despite the above, there is significant internal (technical) cross-border flows of natural gas in the FinEstLat single natural gas transmission entry-exit system, their provision only results in additional variable costs for the natural gas TSOs, which can be clearly identified. Accordingly, the agreement on ITC terms and conditions in Finland, Estonia and Latvia sets out the specific variable costs to be considered eligible, as well as the principles for their allocation and compensation. Such variable cost reimbursement arrangement ensures that the transmission services revenue of the TSOs involved are not detrimentally affected.

To monitor the relevance of the ITC regime of the FinEstLat single natural gas transmission entry-exit system, the TSOs are required to assess, by 1 March of each year, the results of the implementation of the ITC mechanism of the previous year and to inform the NRAs. If necessary, the relevant changes will be made to the FinEstLat ITC regime.

Regulatory account

According to the methodology, the TSO must create a regulatory account, where the difference between planned revenue and uncontrollable costs, and obtained revenue and uncontrollable costs, is attributed after the end of each tariff period, distinguishing between revenue attributed to the cross-border transmission system and the national transmission system. Planned revenues for the gas year are determined considering the forecasted weighted average entry and exit capacity of the transmission system and the corresponding approved entry or exit point tariffs on capacity products. The balance of the regulatory account is taken into account in the determination of the revenue adjustments resulting in changes to the costs of capacity booking service for the next RP. The system operator shall submit the information regarding the regulatory account balance and its justification to the regulator within two months after the end of the gas year.

If the length of the regulatory and tariff period is the same, the revenue adjustment that is attributed to cross-border or national transmission system is determined as follows:

- If the regulatory account balance is negative (revenue obtained is below planned (allowed) revenue), revenue adjustment is equal to regulatory account balance and it increases the costs of capacity booking service for the next RP;
- If the regulatory account balance is positive (revenues obtained surpass the planned (allowed) revenues), revenue adjustment is equal to regulatory account balance, and it reduces the costs of capacity booking service for the next RP;
- If the incurred costs of the capacity booking service (at the cost-group level) during the previous RP are lower than the approved costs of the capacity booking service (at cost-group level) (hereinafter – cost savings), the system operator shall submit justification for the said deviation. Revenue adjustment is equal to cost savings and the planned costs of the capacity booking service attributable to the system users for the next RP shall be reduced for cost savings. If the cost savings are derived from operational efficiency, the revenue adjustment component is equal to 50% of cost savings; and
- If, due to changes in the regulatory framework or the mitigation of extraordinary event(s), there have been unforeseen justified costs during the previous RP, revenue adjustment is equal to justified unforeseen costs and it increases the costs of the capacity booking service for the next RP.

If there is more than one tariff period within the RP, the revenue adjustment that is attributed to the cross-border or national transmission system for a tariff period is determined as follows:

- If the regulatory account balance is negative, revenue adjustment is equal to the regulatory account balance and it increases the costs of the capacity booking service for the next tariff period;
- If the regulatory account balance is positive, revenue adjustment is equal to the regulatory account balance and it reduces the costs of the capacity booking service for the next tariff period; and
- If, due to changes in the regulatory framework or the mitigation of extraordinary event(s), there have been unforeseen justified costs during the previous tariff period, revenue adjustment is equal to justified unforeseen costs and it increases the costs of the capacity booking service for the next tariff period.

If there are several tariff periods within the RP, the revenue adjustment that is attributed to the cross-border or national transmission system for the next RP is determined as follows:

- If the regulatory account balance is negative, allowed revenue adjustment is equal to the regulatory account balance and it increases the costs of the capacity booking service for the next RP;
- If the regulatory account balance is positive, revenue adjustment is equal to the regulatory account balance and it decreases the costs of the capacity booking service for the next RP;
- If the incurred costs of the capacity booking service (at the cost-group level) during the previous RP are lower than the approved costs of capacity booking service (at cost-group level), hereinafter – cost savings, the system operator shall submit justification for the said deviation. Revenue adjustment is equal to cost savings and the planned costs of the capacity booking service attributable to the system users during the next RP shall be

reduced for cost savings. If the cost savings are derived from operational efficiency, the revenue adjustment component is equal to 50% of the cost savings; and

- If, due to changes in the regulatory framework or the mitigation of extraordinary event(s), there have been unforeseen justified costs during the previous RP, revenue adjustment is equal to justified unforeseen costs and it increases the costs of the capacity booking service for the next RP.

When determining the revenue adjustment, the difference between the planned and actual ITC is taken into account.

Annex 5.17 Case study – Lithuania

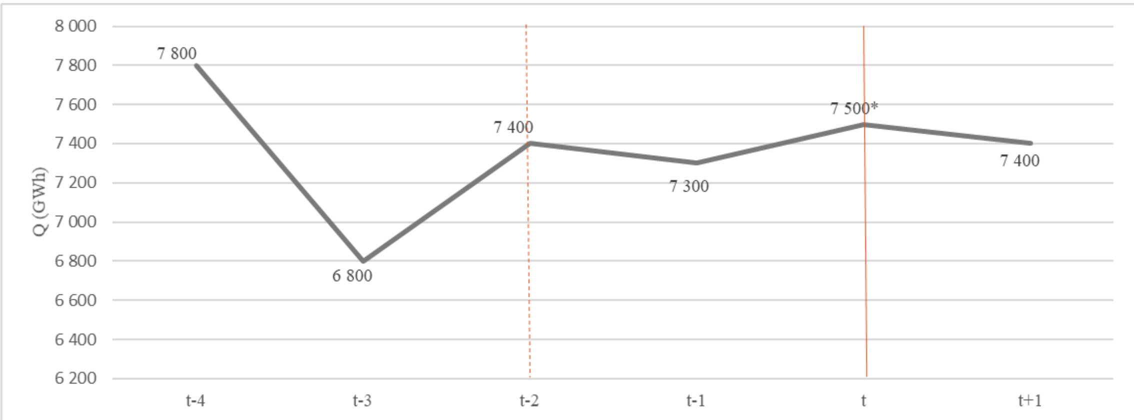
The National Energy Regulatory Council (NERC)[22] applies different methodologies for setting allowed revenues for TSOs and DSOs in the natural gas and electricity sectors, however the main principles are the same. Therefore, the case study for setting the revenue cap[23] for a natural gas DSO is provided below.

A five-year RP 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 return on investment (ROI). Moreover, an incentive scheme is in place, which allows DSOs to earn additional profit if the company reduces its OPEX.

A detailed example[24] 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 RP 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 years (t-2) to (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.



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 the RP, OPEX (excluding personnel costs) is set considering costs incurred in the previous year,[25] 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

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

formula $OPEX_{(t+1),(excl.personnel\ costs)} = OPEX_{(t-1),(excl.personnel\ costs)} * \left(1 + \frac{I_{(t-1)}-e}{100}\right) * (1 + \frac{I_{(t)}-e}{100})$. The example for OPEX (excluding personnel costs) is provided in the table below.

OPEX (excluding personnel costs) in the year (t-1), Thousand EUR	8,000
Inflation (%) in the year (t-1)[26]	3.5
Inflation (%) in the year (t)	2
OPEX (excluding personnel costs) in the year (t+1), Thousand EUR	8,282

Calculation of OPEX (excluding personnel costs) (Lithuania)

Technological needs

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 is 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**

Calculation of technical needs (Lithuania)

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

Depreciation

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.

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

Long term assets	Depreciation (gas sector)	Depreciation (electricity sector)
Buildings	25–70	15-70
Pipelines/electricity lines[27]	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
Other long-term assets	6–10	6-10

Depreciation of periods applied by NCC (Lithuania)

Personnel costs

Personnel costs are calculated similarly to other OPEX. OPEX (personnel costs) for the previous year[28]and the average change in personnel costs in Lithuania (ΔW) for the year (t) and (t+1) are evaluated:

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

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

Calculation of OPEX (personnel costs) (Lithuania)

Taxes

Taxes are evaluated according 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 a decrease in the real estate taxes paid by DSOs and a fall in total taxes by 50% for the main DSO.

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

Regulatory asset base

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

- The value of goodwill;
- Investment assets;
- Financial assets;
- Deferred tax assets;
- Research;
- Study and similar intangible assets;
- Leased assets;
- Assets under construction;[29]

[27] For distribution pipelines a depreciation period of 55 years is applied.
[28] OPEX (personnel costs) set by NCC and factual OPEX (personnel costs) are compared, and the lower value is used in calculations.

- 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; and
- The value of other long-term assets not necessary to perform safe and efficient regulated activity.

Finally, only non-revalued assets are included in the RAB.

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

Return on investment

ROI is calculated as the RAB multiplied by the WACC. In the WACC calculation, the cost of debt and equity risk premium are evaluated by $WACC = R_d * W_D * R_e * \frac{1}{1-m} * W_E$, where:

- R_d is the cap on cost of debt (interest rate, %);
- W_D is the share of debt capital (optimal capital structure);
- W_E is the share of equity capital (optimal capital structure);
- m is the tax rate;
- R_e is the return on equity (%) where $R_e = R_f + \beta * R_{erp}$;
- R_f is the equity risk premium;
- R_{erp} is 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); and
- levered β is the Beta coefficient.

All data used in WACC calculations, except the actual cost of debt of an individual company, is published on the NERC website.[30] Until 2019, the WACC was set for an entire RP. However, during the next RP, the WACC will be adjusted each year in accordance with changes in the DSO's cost of debt. For the main DSO, the WACC is 3.58% for 2019.

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

Calculation of revenue cap

The allowed revenue level is calculated as the sum of all economically justified costs and the 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**

Calculation of revenue cap (Lithuania)

[29] Except for projects of common interest by the TSO.
[30] See https://www.regula.lt/en/Pages/wacc-gas.aspx.

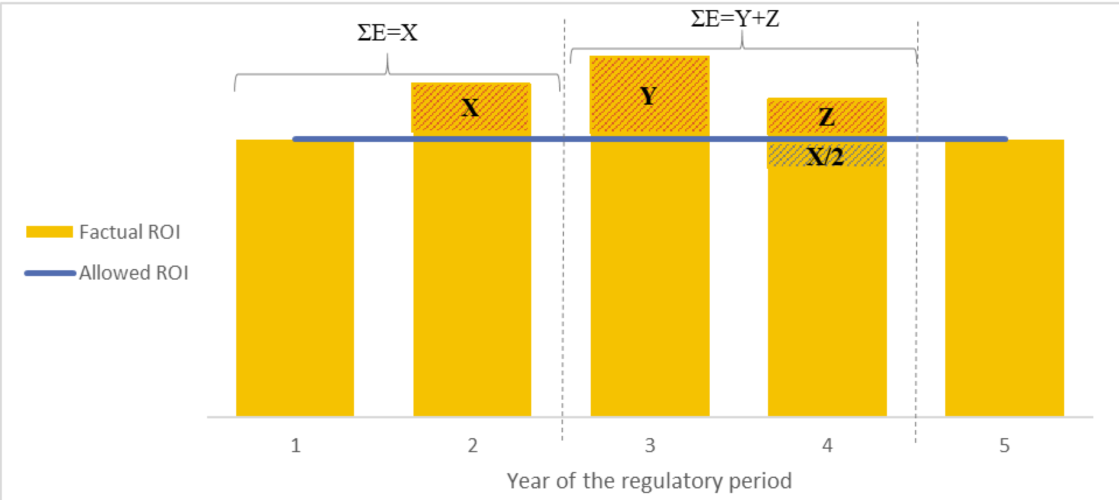
Adjustments within the regulatory period

The revenue cap may be adjusted once a year subject to a 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 the 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 that allows the DSO to earn additional profit if it reduces OPEX. The evaluation of efficiency is carried out in the 2+2+1 (year of the RP) scheme. An example of the evaluation of efficiency for the RP is provided in Figure 5.

In this example, actual ROI is higher than set by NERC in the second (by value X), third (by the value Y) and fourth (by value Z) year of the RP. 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 RP is increased by the value ((X+Y+Z)/2) as additional profit regarding efficiency in OPEX. The other half of the difference in ROI is derived from allowed revenue.



Evaluation of a DSO's efficiency (Lithuania)

The evaluation of efficiency in the first year of the RP is performed likewise, yet the differences of ROI in the third to fifth year of the previous RP are evaluated. 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 on NERC's website.[31]

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

[31] See 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 the data and numbers below are fictitious. Note that Dutch RPs 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 the sake of simplicity below we assume that the base year is just t-2. 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 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 into a situation of yard stick competition. To this end, we take the following steps for each DSO individually:

- Calculate its realised income in the year 2016;
- Calculate its expected efficient cost level for the year 2021; and
- 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.

Step 1: Calculate realised incomes in the year 2016 for each DSO

We do this just before the regulation period 2017-21 starts. So, suppose we are in 2016 and that we have the following realised data for 2015/16 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

2016 tariffs (Netherlands)

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 of 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

Realised income 2016 (Netherlands)

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

Indexed costs 2015 (Netherlands)

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

Estimated costs 2016 (Netherlands)

So, the total cost in 2016 of the sector (A, B, and C together) is €767,982 [9]. Note that in [7] we use the WACC for the period 2017-21.

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

Average tariffs 2016 (Netherlands)

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

Estimated outputs 2021 (Netherlands)

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 2017-21. The total estimated sector output for 2021 then is the sum of this: 963,003 units of output [11]. The efficient cost (sectoral) is than [9] / [11] = 767,982 / 963,003 = €0.797 per unit of output [12].

With this the expected efficient costs that DSOs make in 2021 are:

	Calculation	A	B	C
[13] Expected efficient cost 2021 (euro)	[10]*[12]	95,773	192,874	478,865

Expected efficient costs 2021 (Netherlands)

Step 3: Setting an x-factor for each DSO

With steps 1 and 2 we finally calculate X-factors for the RP 2017-21 as:

	Calculation	A	B	C
[14] Realised income 2016 (euro)	[1]	150,000	223,000	590,000
		↓	↓	↓
X-factor period 2017-21	$1-([15]/[14])^{1/5}$	8.58%	2.86%	4.09%
		↓	↓	↓
[15] Expected efficient cost 2021 (euro)	[13]	95,773	192,874	478,865

X-factors for 2017-21 regulatory period (Netherlands)

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

Annex 5.21 Case study – Norway

Introduction

NVE-RME is the NRA in Norway and is responsible for the regulation of the DSOs and the TSO, Statnett. The DSOs operate local (240 V–22 kV) and regional (33–132 kV) distribution networks. The TSO operates the transmission grid (132–400 kV). In total, there are about 110 DSOs and one TSO.

The network operators are regulated with a combination of direct and economic revenue regulations, as well as compliance monitoring.

Direct regulations define standards, roles and procedures. Compliance monitoring is important to ensure that the operators follow these regulations. The goal of economic revenue regulation is to incentivise the network operators to provide a stable and secure service in a socially efficient manner.

Economic regulation is centred around the annual allowed revenue (AR) for each DSO/TSO. The allowed revenue covers operating cost and depreciation, and provides a reasonable ROI given efficient operation, utilisation and development of the network.

Allowed revenue

The allowed revenue is the sum of the revenue cap (RC) and some pass-through costs (PT). The pass-through costs consist of property taxes, costs to other regulated DSOs/the TSO and some R&D costs that have been approved by NVE-RME. The data used to calculate revenue caps are two years old, and the CAPEX for the current year is included in the pass-through costs to remove this delay. Further, any costs of energy not supplied (CENS) during the current year are deducted from the allowed revenue. The CENS arrangement will be explained later.

This provides the following formula for the allowed revenue: $AR = RC + PT - CENS$.

The revenue is subject to regulatory control. Excess or deficit revenue for a given year is calculated as the difference between actual collected revenues and allowed revenues in a year. NVE-RME decides an excess/deficit revenue balance every year. The balance is to be adjusted towards zero over time, through tariff changes. Excess revenues must be reimbursed to the customers, while deficit revenues may be recovered.

Revenue cap

The revenue cap is set annually, based on a formula that combines cost recovery and a cost norm resulting from benchmarking models: $RC = (1 - \rho) * cost\ base + \rho * cost\ norm$.

Currently, ρ is 60%. To strengthen the incentives for efficient operation further, ρ will be increased to 70% from 2023.

The DSOs and TSO annually report economic and technical data to NVE-RME through an extensive system of auditing and control mechanisms. These data provide the basis for the revenue cap calculation. Due to a time lag in the reporting scheme, there is a two-year lag in the model. For the revenue cap for 2022, data from 2020 is used as base, and for revenue cap 2023, data from 2021, etc.

Cost base

The cost base is the sum of three elements: OPEX, CAPEX and CENS.

Operation, maintenance and losses (OPEX)

The OPEX includes operation and maintenance (O&M) costs and the cost of network losses. The O&M costs are two years old and adjusted with an inflation index. The cost of network losses are the physical losses in MWh multiplied by a standardised price from the DSO's prize area for the current year.

Capital costs (CAPEX)

CAPEX is defined as the yearly depreciation plus ROI. The investments are defined as the book value per 31 December + 1% working capital. The companies are free to choose the appropriate depreciation rate, that should reflect the expected technical lifetime for the asset in their area.

The regulatory RoR is decided by a WACC model $WACC_{pre-tax} = (1 - G) * \left[\frac{R_f + infl + \beta_e MP}{1-t}\right] + G * (Swap + P_d)$, where:

- G is the gearing rate (debt share of total capital): 0.6;
- R_f is the real risk-free rate for equity: 1.5%;
- $infl$ is the moving average of four-year inflation, observations from the previous year and the current year, and expected inflation for the next two years;
- β_e is the equity beta: 0.875, estimated from an asset beta of 0.35;
- MP is the market premium: 5%;
- $Swap$ is the nominal rate for debt: annual average of five-year swap rate;
- P_d is the debt premium: annual average of credit spread for five-year bonds for the power sector; and
- t is the tax rate: 22%.

Costs of energy not supplied (CENS)

For every outage, a cost of the energy not supplied is calculated. The costs are defined through a set of functions depending on the duration of the outage, the customer type, time of day, week and year and whether the outage was announced in advance. The cost functions have been developed over the years and are meant to reflect the socio-economic costs of outages. Research projects have explored customers' willingness to pay to avoid outages and estimated the costs of outages.

Cost norm

The cost norm is meant to represent the averagely efficient cost level among the companies. For the TSO, there are not many similar companies to compare them to. We apply a separate model for them where they are benchmarked against their own historical data. We will not describe this further in this report, but rather describe the cost norm model for the DSOs. This cost norm is calculated in three steps: a DEA model, correction for heterogeneity and a calibration of the cost norms. The calculation is done yearly.

Stage 1: DEA model

We have two DEA models, one for local distribution and one for regional distribution. In both models there is one input, TOTEX, similar to the cost base, except that network losses are not included in the regional distribution model. CENS is part of the TOTEX, even though it is not really a cost since the DSO does not pay this to anyone. But CENS reduces the allowed revenue, so it has the same effect as a cost in practice. When we include it in the TOTEX, the DSO must balance this cost element against other cost elements, to find the best way to keep TOTEX as low as possible.

In the local distribution model, there are three outputs: number of customers, number of kilometres with HV grid, and number of substations. In the regional distribution model there are four outputs, all weighted values of the physical components in the grid: the weighted value of overhead lines, underground cables, subsea cables and station components.

Both models are input minimising models assuming constant returns to scale (CRS). The yearly observations are compared against a dataset that consists of the average of the data for the last five years. This is to keep the frontier a bit more stable and thus avoid large variations from year to year.

Stage 2: Correcting for heterogeneity/Z-variables compared to the peer

We use regression analysis to identify and correct for the impact of heterogeneity on the DEA scores from stage 1. We have defined a number of Z-variables based on the geographical location of the grid. We can define for example, how much of the grid goes through forest or how far the grid is from the coastline. We also have structural variables, like the share of underground or subsea cables, for example.

There are five Z-variables in the local distribution model and one in the regional distribution. Some of the Z-variables are composite variables that we have calculated, using principal component analysis:

Local distribution	Regional distribution model
Share of underground cables (centralisation)	Comp variable 4: forest and slope
Share of network components located in forest	
Comp variable 1: mountain environments: slope around grid, coniferous forest and local production	
Comp variable 2: coastal environments: share of subsea cables, distance to coast, number of islands	
Comp variable 3: cold environments: latitude, snow, low temperature	

Z-variables for DEA model (Norway)

In stage 2, we calculate the Z values for the peers for each of the DSOs. The DEA score from stage 1 can be corrected up or down, depending on whether a DSO has “worse” conditions than its peer or not. If the peer has more of the grid through forest than the DSO we evaluate, the DEA score will be lowered in stage 2.[32]

Stage 3: Calibrating the level of the cost norms

After stage 2, all the DSOs have a DEA score that is adjusted for the heterogeneity. This is multiplied by the cost base to find the cost norm. For most DSOs, the cost norm will be lower than the cost base. The cost base includes RoR on the capital, which means only the most efficient DSOs would be able to achieve the WACC in return on their investments if we used the cost norm from stage 2. In stage 3, however, the cost norms are adjusted so the sum of them equals the sum of the cost base for all DSOs. Thus, the industry as a whole gets all its costs covered and receives the WACC on its investments. But the return for each DSO will differ. The averagely efficient DSO can achieve the WACC on their investments. A DSO that

[32] Stage 2 is more thoroughly described in http://www.deazone.com/proceedings/DEA2014-Proceedings.pdf, pp 334-342.

is more (less) efficient than the average can achieve a higher (lower) return on their capital. This gives strong incentives for the DSOs to improve their efficiency. It also gives incentives for the most efficient DSOs to maintain their efficiency, since the model is calculated every year.

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 (the Portuguese NRA) to promote the integration of low voltage (LV) installations (supply points) into smart grids. It can also be seen as an incentive for the "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 retail 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[33] ("Regulation for Smart Grid Services") which sets the terms and rules applicable to services delivered by LV 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 had 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 RAB, 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, LV distribution activity is regulated through a price cap on 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 OPEX achieved by the LV DSOs, and thus

[33] See 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/.

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 base at the beginning of each RP. 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 over 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 RP. 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 expression $ISI_{LV,w}^{LVO_j} = \Delta NI_w^{LVO_j} * K_w^{LVO_j} * T_w$, where:

- $ISI_{LV,w}^{LVO_j}$ is the total amount of the incentive for year w, awarded to LV DSO j (LVO_j);
- w is the reference year for the application of the incentive;
- $\Delta NI_w^{LVO_j}$ is 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 $w-1$;
- $K_w^{LVO_j}$ is the parameter that represents the annual value of the incentive $ISI_{LV,w}^{LVO_j}$ for the year w (or the benefit shared with the LV DSO);
- LVO_j is the LV DSO eligible for the incentive; and
- T_w is the parameter that represents the number of years of application of the incentive.

At the end of T_w, the value of the parameter $K_w^{LVO_j}$ 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: $TISI_{LV,t}^{LVO_j} = \sum_{w=2019}^{t-2} \frac{ISI_{LV,w}^{LVO_j}}{T_w}$.

Thus, from the 2022[34] network tariffs onwards, the ISI amounts will be included in the DSO's annual allowed revenues (relative to 2020 with a two-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.

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 ($K_w^{LVO_j}$) and the incentive's length (T_w). To define them,[35] 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;[36]
- 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 RP.

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

[34] 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 two 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.
[35] For further details about the parameters, please refer to the following document: https://www.erse.pt/media/h03d0s0k/proveitos-e-ajustamentos-2020.pdf.
[36] Cost benefit study on smart meter rollout, as established by Ordinance nº231/2013.

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

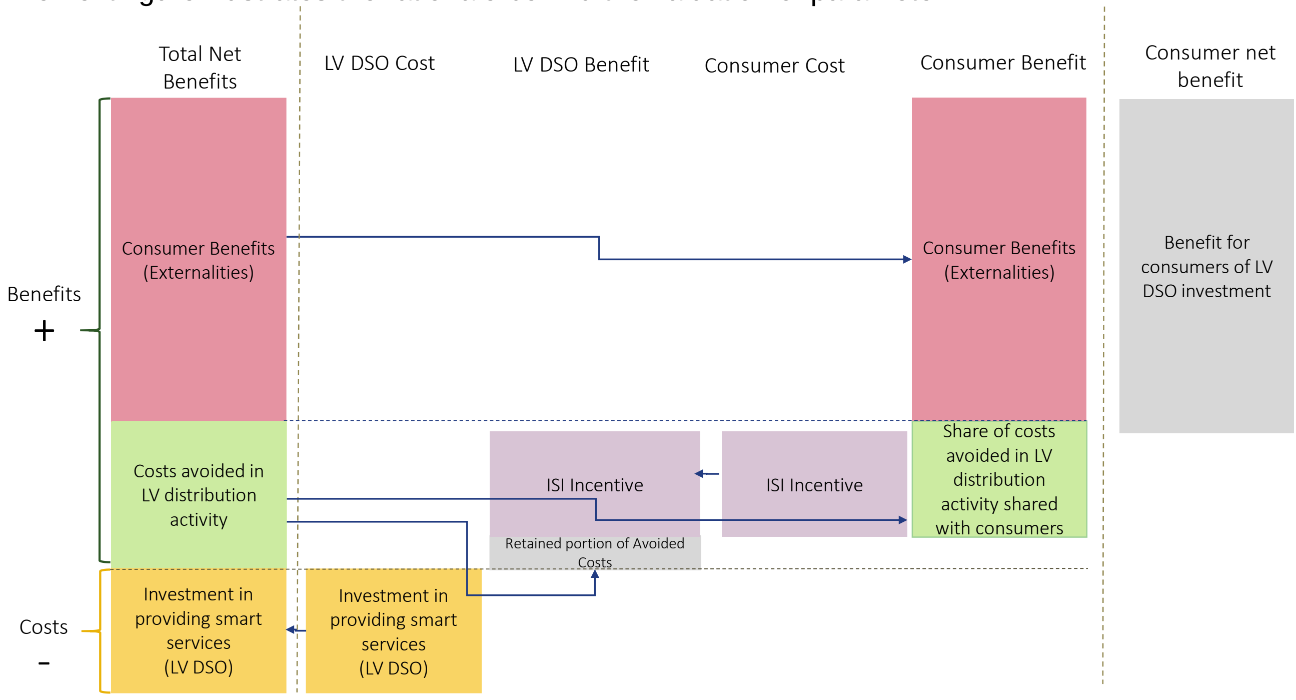
SI parameters (Portugal)

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[37] 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,[38] 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:



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.

[37] Such as savings from more efficient electricity consumption.
[38] Through cost base revisions and the 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[39] and its justifying report.[40]

The annual remuneration received by the transmission company i is calculated by summing up the components of the following formula for year n: $R_n^i = RI_n^i + ROM_n^i + REVU_n^i + ID_n^i$, where:

- RI is investment remuneration;
- ROM is operation and maintenance (O&M) remuneration;
- $REVU$ is remuneration for the extended regulatory lifetime of assets; and
- ID is the 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.

[39] See https://www.boe.es/buscar/act.php?id=BOE-A-2019-18260.
[40] See 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	1 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	1 January 2018	Iberian Peninsula	40 years	900,000	-
3	Single-phase transformer (400/220 kV), 200 MVA	1 January 2019	Iberian Peninsula	40 years	1,800,000	-
4	Overhead single duplex transmission line of 8 km, 220 kV and 200 MVA	1 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	1 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	1 January 2018	Balearic Islands	40 years	4,500,000	Considered as a unique facility

Asset types (Spain)

The remuneration is calculated for the RP that ranges from 1 January 2020 to 31 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 31 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 1 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 1 January 1998 to 31 December 2017: there is a recognised investment value for each asset, whose calculation is based on the methodology established by Royal Decree 1047/2013.[41] For those assets commissioned

[41] See https://www.boe.es/buscar/act.php?id=BOE-A-2013-13766.

from 1 January 2015 onwards, the investment value is calculated as the average of the reference values and the audited cost of the asset; and

- For facilities commissioned from 1 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[42] of CNMC has established that the investment reference values for the RP 2020-25 are the ones established in the catalogue of Order IET/2659/2015,[43] which are shown below, for the assets in the example.

Electricity transmission assets	$VI^{\text{reference value}}$	
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	

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 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, AC/DC converter stations, as well as remote control stations. Additionally, investments in pilot projects could be considered as unique ones.

Circular 2/2019[44] sets the RoR of investments based on a WACC methodology. For electricity transmission in the RP 2020-25, the RoR takes a value of 5.58% (nominal pre-tax). There is an exception for the year 2020, when RoR 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.

[42] See https://www.boe.es/buscar/act.php?id=BOE-A-2019-18262.
[43] See https://www.boe.es/buscar/act.php?id=BOE-A-2015-13487.
[44] See https://www.boe.es/buscar/act.php?id=BOE-A-2019-16639.

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

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

$$\mathrm{RI}_n^j = \mathrm{A}_n^j + \mathrm{RF}_n^j$$

$$\mathrm{A}_n^j = \frac{\mathrm{VI}^j}{\mathrm{VU}^j} \qquad \mathrm{RF}_n^j = \mathrm{VN}_n^j \cdot \mathrm{TRF}_p$$

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

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

$$\mathrm{FRRI}_{n-2}^j = (1 + \mathrm{TRF}_{APS})^{tr_j}$$

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

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
$\mathrm{VI}^{\text{audited}}$	audited investment cost
$\mathrm{VI}^{\text{reference value}}$	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

Calculating investment remuneration (Spain)

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 1 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 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	$\mathrm{VI}^{\text{audited}}$ (€)	$\mathrm{VI}^{\text{reference value}}$ (€)	δ	AY (€)	TRF_{APS}	tr[45]	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[46]	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[47]	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							

Investment values (Spain)

[45] We assume that the date when it obtains the operating licence and the commissioning date are the same.

[46] There are no reference values for unique facilities; this is the investment value of the uniqueness request ($\mathrm{VI}_{n-2}^{j,\text{uniqueness request}}$).

[47] 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.

				2020	2021	2022	2023	2024	2025
			TRF_P	6.0033%[48]	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[49]	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**

Investment remuneration (Spain)

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

O&M reference values (Spain)

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:

- Overhead lines at 400 kV;
- Overhead line at 220 kV;
- Conventional substation bay at 400 kV; and
- Transformer with primary at 400 kV.

[48] According to the fourth Additional Provision of Circular 5/2019, for 2020 the RoR has been established as 6.0033% for the first year of the first RP in which this methodology applies (2020).
[49] Asset considered as unique facility.

For assets considered as unique facilities, 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 one in the first year and can be adjusted from the second year onwards, according to the information provided by the transmission agent to 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

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

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

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

$$\mathrm{FRROM}_p^j = (1+\mathrm{TRF}_p)^{\,tr\_om_j}$$

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

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

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
tr_om_j	number of years O&M remuneration delay
$ROM_{uniqueness}$	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

Calculating O&M remuneration (Spain)

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 RP, to the remuneration calculated according to the reference values of the current RP. If the companies are able to lower their O&M costs during an RP, the O&M reference values of the next RP 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 in 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 RP 2020-25), 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 second Additional Provision of Circular 5/2019, and that the O&M reference value for the current RP is €3,056 per km and circuit, the efficiency factor takes a value of 0.8%, as shown below:

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

				2020	2021	2022	2023	2024	2025
Family	Asset	TRF_P		6.0033%[50]	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[51]	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**

O&M remuneration (Spain)

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 on 1 January 1978. Consequently, its regulatory lifetime (40 years) ended on 31 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

Extending the regulatory lifetime of assets (Spain)

[50] According to the fourth Additional Provision of Circular 5/2019, for 2020 the RoR has been established as 6.0033% for the first year of the first RP in which this methodology applies (2020).

[51] 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.

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**

Remuneration for the extension of regulatory lifetime (Spain)

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:

- Overhead lines at 400 kV;
- Overhead lines at 220 kV; and
- 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

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

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

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

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

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

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

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

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

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

Calculating the grid availability incentive (Spain)

				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	IIF_{III}	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}[52]				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}[53]				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**

Grid availability incentive (Spain)

Step 5: Determination of the financial prudence penalty

A penalty on the remuneration is established for those companies that 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[54] of the CNMC. The maximum penalty is 1% of the remuneration.

Nevertheless, as established in the third 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

Calculating the financial prudence penalty (Spain)

[52] The minimum availability index required for the company to not be penalised is determined as the average of the availability index in the three years prior to year n-2. In consequence, for years 2023-25 the minimum availability indexes have been calculated for the fictional example, but for years 2020-22, we have assumed their values.
[53] According to Article 15.7 of Circular 5/2019, ($D_{period\ target}$ - D_{min}) cannot take a value lower than 0.1.
[54] See 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	Capitalised expenses	0	0	0	0	0	0
	Operating result	1,200	1,200	1,100	1,000	1,000	1,100
	Depreciation[55]	200	300	300	300	300	300
	Impairments and gains/ losses on disposal of non-current assets[66]	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[66]	300	250	200	110	100	80
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**[56]	**-2,042**[67]	**0**[67]	**0**	**0**	**0**

Financial prudence penalties (Spain)

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 the remuneration adjustment is applied if some assets and resources have been used in other activities, and the financial prudence penalty is applied.

[55] To make the calculation, these items change their sign.
[56] The penalty does not apply until 2023, according to the third Additional Provision of Circular 5/2019.

	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**

Total remuneration (Spain)

Annex 5.28 Case study – Sweden

Electricity network regulation, regulatory period 2020-23

General information

Before the RP the NRA, Ei, determines the allowed revenues for the network operators, partly based on forecasts, for every electricity network operator, normally for a four-year period, which is presented as a total for the entire customer collective of that operator. For details see formula 1. After the RP Ei updates the revenue caps and replaces the forecasts with the actual outcome. After the RP an adjustment of the revenue caps is also made by an annual supplement or deduction, 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 describes the calculation of the revenue caps after the RP.

***Formula 1* =** Capital costs based on opening RAB and projected investments and disposals + controllable costs, normally based on four-year historical costs, deducted for efficiency requirements + non-controllable costs based on forecasted data.

***Formula 2* =** Capital costs based on opening RAB 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.

Differences in the price level are also adjusted after the period. The practical handling of the indexing is presented in the section below.

The revenue cap that is set before the RP is determined by an amount for the whole RP of four years. In the decision it is clarified that the revenue cap after the RP must be adjusted for every year with different indexes. The use of the indexes for cost and revenues should be limited to being used where it is directly stated in the legislation. The legislation states that the “factor price index for buildings” is to be used for the RAB, and “factor price index for electricity network companies, sub-index operation and maintenance costs, controllable” shall be used to index 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.

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, 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 for each year’s price level with the CPI.

Capital base and cost of capital

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. To calculate the capital cost based on this method, the network assets must be given a replacement value, that reflects what the cost to acquire and commission an entirely new asset would be today. This includes project planning, materials, certain labour and material costs, preparation, etc., 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, but if the first cannot be used, the second method should be used and so on. The methods according to the ranking are as follows: 1) catalogue cost, 2) initial acquisition value, 3) book value and 4) other reasonable value. Note that, depending on the method, renumeration is done in real terms according to the factor price index for buildings, the construction cost trend mentioned in the above section. Below follows an example of assets that will be used to illustrate the calculation of the revenue cap. In the example we do not consider any loans for network reinforcement or any costs for interruptions, that are handled a bit differently from the described methodology below. All monetary figures are presented in SEK.

Asset category	Asset_ type	Technical spec	Quantity (km, number)	Catalogue nr	Voltage	Catalogue cost (for Q=1)	Replacement value	Year_ from
Other lines, area concession	Underground cable, city	N1XV(E) 4x150 mm²	0.0051	NG1 4435	0.4	888,839	4,562	2009
Other lines, area concession	Underground cable, populated area	PEX 3x150 mm²	1.0113	NG1 4523	12	713,572	721,638	1959
Meter	Meter	Mätare kategori 1	304	NG1 5951	0.4	2,295	697,680	2016 H2
Network station	Station	Nätstation	26	NG1 5224	12/0.4	178,513	4,641,338	2005
Transformer	Transformer	500 kVA	6	NG1 5922	12/0.4	111,250	667,500	1981
Total cost for replacement							6,732,718	

Example of reported assets with catalogue costs[57] (Sweden)

The DSOs only report quantity, investment year (year_from), and the catalogue nr. The other data is generated in the system. The assets in the table above are used to illustrate how the cost of capital is calculated. Since 2011 CAPEX has been calculated semi-annually and the notation of H2 means the asset has been taken into operation in the second half of the year.

Depreciation ratio

Depreciation ratios that electricity network assets have for the RP 2020-23 are given in table 42 below. Where economical depreciation is the normal depreciation time, if an asset is fully functional after that time it might get an extended lifetime and be included in the RAB up to the maximal depreciation time. The maximal depreciation time is a 25% extension compared to the economical depreciation time.

[57] No planned investments or disposals.

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 HV 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

Regulatory depreciation ratios for electricity assets (Sweden)

When putting an age to the assets introduced in table "*Example of reported assets with catalogue costs* ", we can see that all except one are within the economical depreciation time. Asset 2 is within the maximal depreciation time until the end of 2022. The age of the assets for each half year in the RP is shown in the table below.

Assets	Age							
	2020 H1	2020 H2	2021 H1	2021 H2	2022 H1	2022 H2	2023 H1	2023 H2
Underground cable, city	10	10	11	11	12	12	13	13
Underground cable, populated area	60	60	61	61	62	62	63	63
Meter	3	3	4	4	5	5	6	6
Station	14	14	15	15	16	16	17	17
Transformer	38	38	39	39	40	40	41	41

Age of the assets (Sweden)

Calculation formulas for the cost of capital (CAPEX)

CAPEX is calculated as the sum of depreciation and return on capital. If a fixed asset is younger than the economic depreciation time, the calculation is done as $Depreciation\ per\ half\ year\ = 0.5 * \frac{Replacement\ value}{Economic\ Depreciation\ Time}$, and $Return, half\ year = 0.5 * Replacement\ value * \frac{(Economic\ depreciation\ time - age\ of\ the\ asset)}{Economic\ depreciation\ time} * Real\ WACC\ before\ tax.$

If an electricity grid installation is older than the economic depreciation period but younger than the maximum depreciation period (i.e. asset 2), the calculation is done as $Depreciation\ per\ half\ year\ = 0.5 * \frac{Replacement\ value}{Age\ of\ the\ asset}$, and $Return, half\ year = 0.5 * Replacement\ value * \frac{1}{Age\ of\ the\ asset} * Real\ WACC\ before\ tax.$

Also note the following:

- The cost of capital is calculated semi-annually (H1 and H2) which explains the multiplication by 0.5 in the formulas above. If a change is made in the RAB (investment or disposals) at some point during the first half of the year, this change will first affect the RAB in the next six months. For example, if an investment is made in 2020 H1, it will be added to the RAB in 2020 H2. This means that on average there is a three-month delay for RAB changes; and

- The first year the electricity network asset has in the capital base is zero, not one. For example, when the economic depreciation period is 30 years, this will generate full capital cost during the years zero to 29, which is then 30 years.

For the assets introduced in the table below the cost of capital would be:

	Depreciation							
Assets	2020 H1	2020 H2	2021 H1	2021 H2	2022 H1	2022 H2	2023 H1	2023 H2
Underground cable, city	46	46	46	46	46	46	46	46
Underground cable, populated area	6,014	6,014	5,915	5,915	5,820	5,820	0	0
Meter	34,884	34,884	34,884	34,884	34,884	34,884	34,884	34,884
Station	58,017	58,017	58,017	58,017	58,017	58,017	58,017	58,017
Transformer	6,675	6,675	6,675	6,675	6,675	6,675	6,675	6,675
Sum	**105,635**	**105,635**	**105,536**	**105,536**	**105,441**	**105,441**	**99,621**	**99,621**

Depreciation of the assets (Sweden)

Each cell is calculated as the replacement cost divided by the depreciation time, except for asset two, where the actual age is used instead of depreciation time until it reaches its maximal depreciation time.

To calculate the return, we must first adjust for the age of the asset (i.e. deduct already depreciated capital). Below, we can see the age adjusted RAB for the example assets.

	Age adjusted RAB							
Assets	2020 H1	2020 H2	2021 H1	2021 H2	2022 H1	2022 H2	2023 H1	2023 H2
Underground cable, city	3,649	3,649	3,558	3,558	3,467	3,467	3,376	3,376
Underground cable, populated area	12,027	12,027	11,830	11,830	11,639	11,639	0	0
Meter	488,376	488,376	418,608	418,608	348,840	348,840	279,072	279,072
Station	3,016,870	3,016,870	2,900,836	2,900,836	2,784,803	2,784,803	2,668,769	2,668,769
Transformer	160,200	160,200	146,850	146,850	133,500	133,500	120,150	120,150

Age adjusted value of the RAB (Sweden)

From the age adjusted RAB, we multiply by the WACC to get the return on capital.

	Return on capital							
WACC = 2.35%	2020 H1	2020 H2	2021 H1	2021 H2	2022 H1	2022 H2	2023 H1	2023 H2
Underground cable, city	43	43	42	42	41	41	40	40
Underground cable, populated area	141	141	139	139	137	137	0	0
Meter	5,738	5,738	4,919	4,919	4,099	4,099	3,279	3,279
Station	35,448	35,448	34,085	34,085	32,721	32,721	31,358	31,358
Transformer	1,882	1,882	1,725	1,725	1,569	1,569	1,412	1,412
Sum	**43,253**	**43,253**	**40,910**	**40,910**	**38,566**	**38,566**	**36,089**	**36,089**

Return on capital[58] (Sweden)

CAPEX for each year is presented below.

CAPEX	2020	2021	2022	2023
SEK	297,776	292,892	288,015	271,420

CAPEX, SEK (Sweden)

After the RP the cost of capital is corrected for actual investments and disposals, as well as indexed to the price level for each year.

Calculation of controllable costs and efficiency requirements

The controllable costs are calculated based on an average of four years of historical data two years before the start of the RP. For the RP 2020-23, the controllable costs correspond to the companies' historical costs for the years 2014-17. In cases where a company is newly established, or its operating and maintenance costs during the RP are assumed to deviate significantly from the historical data, the company's forecasts for this cost item can be used instead, which are then replaced with actual data after the period.

Regarding how controllable costs are described in principle in the table below, some numbers have been put into the cells to illustrate how the relation between components can be. First, all components of OPEX are added into one post for the historical costs. The combined post is in turn adjusted for some specific cost elements, including (among others) the non-controllable costs. In some cases, prior to the RP, the DSOs have the possibility of correcting historical values.

[58] Per half year = (age adjusted RAB*WACC)/2.

			2014	2015	2016	2017
Costs related to transit and purchase of energy			83,000	84,660	86,353	88,080
Material			1,500	1,530	1,561	1,592
Other external costs			65,000	66,300	67,626	68,979
Labour cost			42,000	42,840	43,697	44,571
Other operating expenditure			0	0	0	0
Sum	(A1)		**191,500**	**195,330**	**199,237**	**203,221**
Adjustments						
Changes in inventory			0	0	0	0
Activated work for own account			0	0	-5,000	-7,000
Non-controllable costs (see next chapter)			-61,060	-62,480	-63,900	-65,320
Compensation for interruptions			-1,225	-750	-1,100	-560
Leasing costs for assets included in the RAB			-350	-524	-487	-431
Adjusted controllable costs	B1(=A1-adjustments)		**128,865**	**131,576**	**128,750**	**129,910**
Adjustment for tangible assets not included in the RAB						
		2013	**2014**	**2015**	**2016**	**2017**
Book value		88,000	140,000	130,000	118,000	
Depreciations			10,000	12,000	12,000	12,000
r =	*4.12%*					
Cost for tangible assets not in the RAB	(B2)		13,626	17,768	17,356	16,862
Total controllable costs	C1(=B1+B2)		**142,491**	**149,344**	**146,106**	**146,772**
Indexation to base year (2018)						
Index to 2018			1.10009	1.0811	1.0526	1.0256
Total controllable costs, price level 2018			156,868	161,456	153,791	150,529
Average controllable costs 2014-17			**155,661**			

Calculation of controllable OPEX (Sweden)

From the average cost for 2014-17, an annual deduction due to efficiency requirements is made to all companies' considerable operating and maintenance costs.

For local DSOs, the annual efficiency requirements are individually calculated 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 the claim can amount to is 1%, and the highest level of the claim means an annual reduction of 1.82% of the controllable costs.

In summary, the method implies that Ei, when determining the efficiency requirement, uses the DEA method, which is based on comparisons between the local area network companies' performances. Each network company receives an individual requirement based on how their 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%. 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 consists of two input variables that constitute the resource consumption, controllable costs (OPEX) and capital costs (CAPEX), and five production variables: delivered energy distributed on HV and LV networks, the number of subscriptions, the number of network stations and the highest value of subscribed and withdrawn power to overlying networks.

In the calculation, outliers are identified as non-comparable DSOs according to set criteria for super-efficiency: $Effi > q\ (75) + 2 * [q\ (75) - q\ (25)]$, where:

- $Effi$ is the measure of efficiency for companies, which is obtained by driving with super efficiency;
- q (75) is the efficiency of the third quartile for all companies; and
- q (25) is 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 two.

As we move from potential to efficiency requirements, we have also built in several restrictions. These restrictions are as follows:

- The time to realise the full potential is set at eight years, that is, two RPs;
- 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% per year.

No benchmarking is used for the regional DSOs or the TSO; these receive the lowest annual requirement of 1%.

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 has been submitted to our government where it would be possible to apply the requirement to all costs. This can begin to apply during the next RP (2024-27) at the earliest.

With an annual efficiency requirement at 1% (the lowest possible), the example above would generate the following controllable costs for the RP 2020-23.

	2014	2015	2016	2017
Controllable costs before efficiency requirement	155,661	155,661	155,661	155,661
Deduct efficiency requirement 1% per year	154,104	152,563	151,038	149,527
Controllable costs for 2020-23	607,233			

Controllable costs for 2020-23 (Sweden)

After the period the controllable costs are indexed to the price level for each year.

Non-controllable costs

The DSOs report projections of non-controllable costs prior to the RP. These are treated as a pass-through cost and updated with the actual outcome at the end of the period (for TSOs there are different cost elements than the ones presented below). The two largest components are subscription fees to other networks, and costs for network losses (purchase). In the table below the different non-controllable costs are presented, as well as how they can be projected before an RP.

	2020	2021	2022	2023
Cost for network losses (purchase)	15,000	16,000	17,000	18,000
Cost for network losses (own production)	0	0	0	0
Subscription fee to other network(s)	50,000	50,000	51,000	51,000
Connection fees to other network(s)	0	0	0	0
Compensation to producers for production	4,000	5,000	5,000	6,000
Government fees	2,000	2,000	2,000	2,000
Capacity reserve	0	0	0	0
Total estimate for the period	**296,000**			

Non controllable costs for 2020-23 (Sweden)

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 RP 2020-23 deviate from the established revenue cap for the same period, the revenue cap for the next period 2024-27 shall decrease or increase by the differing amount. In addition, if a company's total revenue from network operations during the RP 2020-23 exceeds the established revenue cap with more than 5% for the same period, an overcharging supplement will be added. A new rule from 2021 makes it possible for the DSOs to apply for an extension of non-utilised revenues in order to increase investments.

The total revenue cap for 2020-23 (ex ante)

The numbers presented in the previous sections add up to the revenue cap presented below. No extra amount from previous periods is assumed in this case. Note that this are just fictive numbers. Of the total revenue caps decided for 2020-23, CAPEX and non-controllable costs constitute around 37% each, while controllable costs constitute 25% of the total revenue caps decided. The numbers in the revenue cap are presented in 2018-year price level.

		2018 price level
CAPEX		1,124,422
OPEX		
	Controllable	607,233
	Non-controllable	296,000
Revenue cap 2020-23		2,027,655

Final revenue cap (Sweden)

After the RP, CAPEX will be updated based on actual investments and disposals, and the return on capital will be adjusted based on the incentives for quality of supply and efficient network utilisation. The non-controllable costs will be updated with the actual outcome, as well as compensation for interruptions.