Regulatory Approaches to Revenue Setting for Electricity Transmission and Distribution System Operators among ERRA Member Organizations

MAIN REPORT

Submitted to ERRA by:

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Abbreviations and acronyms

AL	Albania
AT	Austria
AZ	Azerbaijan
BG	Bulgaria
CoD	Cost of debt
CoE	Cost of equity
CPI	Consumer Price Index
CRP	Country risk premium
CZ	Czechia
DSO	Distribution system operator
ECA	Economic Consulting Associates
EE	Estonia
ERP	Equity risk premium
ERRA	Energy Regulators Regional Association
FCM	Financial Capital Maintenance
GE	Georgia
HU	Hungary
LRAIC	Long-run average increment cost
LT	Lithuania
LV	Latvia
MD	Moldova
MK	North Macedonia
MO	Member organisation (of ERRA)
NG	Nigeria
OM	Oman
PE	Peru
PK	Pakistan
PL	Poland
RAB	Regulatory asset base
RFR	Risk-free rate
ROR	Rate of return
SK	Slovakia
TR	Turkey
TSO	Transmission system operator
WACC	Weighted average cost of capital
XK	Kosovo

1 Introduction

This study investigates approaches for regulating the revenue of electricity transmission and distribution system operators (TSOs and DSOs). The study draws on survey data collected from 20 regulators who are members of the Energy Regulators Regional Association (ERRA). The study is presented in four steps: (i) a review of the regulatory governance structures in each country; (ii) a description of the overall tariff framework in each country; (iii) a deeper analysis of the components underlying the broader framework; and (iv) an explanation of the adjustment mechanisms adopted (see Figure 1).

Figure 1 Four steps for reviewing regulatory principles

1. Regulatory governance

Governance and accountability	Transparency
▪ Regulatory independence ▪ Concentration of decision-making power ▪ Developing and approving regulations ▪ Appeals procedures	▪ Transparency of allowed revenue determination process ▪ Accounting transparency

2. Overall tariff framework

Tariff regulation methods	Length of regulatory period	Revenue requirement	Efficiency factors
▪ Rate-of-return ▪ Cost-plus ▪ Revenue cap ▪ Price cap	▪ Long versus short ▪ Price resets	▪ Building blocks ▪ Accounting ▪ Cash-based ▪ Totex	▪ X-efficiency factors in price- and revenue-cap regimes

3. Cost and revenue determination

Opex	Capex and RAB	WACC	Other
▪ Determining allowed opex ▪ Allowed vs actual ▪ Controllable vs uncontrollable ▪ Regulated vs unregulated ▪ Efficiency factors	▪ Determining allowed capex ▪ Allowed vs actual ▪ Capex in the RAB ▪ Asset value ▪ Depreciation ▪ Capex in law ▪ Tendering	▪ Tax and inflation ▪ Cost of debt ▪ Cost of equity ▪ Equity beta ▪ Equity risk premium ▪ Gearing ▪ Risk-free rate	▪ Losses ▪ Quality of supply

4. Revenue adjustments

- Adjusting for difference between allowed/actual revenue
- Adjusting for difference between allowed/actual pass-through costs
- Adjusting for inflation

To collect data for the study, ERRA issued a survey, which was developed by the Secretariat and reviewed by ECA (see Annex A4), to 21 ERRA members. Responses were received from 20 members, resulting in a response rate of 95%. The respondents are listed in Table 1 alongside their ISO country codes, which are used throughout the report.

Table 1 Countries surveyed

Region	Countries	ISO codes
Americas	Peru	PE
Caucasus	Azerbaijan, Georgia	AZ, GE
Europe	Albania, Austria, Bulgaria, Czechia, Estonia, Hungary, Latvia, Lithuania, Moldova, North Macedonia, Poland, Slovakia, Turkey, Kosovo[2]	AL, AT, BG, CZ, EE, HU, LV, LT, MD, MK, PL, SK, TR, XK
Middle East and North Africa (MENA)	Oman	OM
South Asia	Pakistan	PK
Sub-Saharan Africa (SSA)	Nigeria	NG

In line with the steps in Figure 1, the study is structured around the four sections (and also has four annexes):

- **Section 2 (Regulatory governance):** An examination of the governance, accountability and transparency of the regulatory authority in each country.
- **Section 3 (Overall tariff framework):** A review of the broad approaches to regulating the TSOs and DSOs in each country. We cover the tariff regulation methods adopted to control the regulated entity's tariffs, the length of the regulatory period, the method used to calculate the value of the revenue requirement, and the role of X-efficiency factors.
- **Section 4 (Cost and revenue determination):** A detailed analysis of the components used in the broad regulatory approach. We cover opex, capex, the regulatory asset base (RAB), the weighted average cost of capital (WACC), quality of supply, and technical and commercial losses.
- **Section 5 (Revenue adjustments):** A review of how regulators adjust the tariff between regulatory reviews to minimise the divergence of revenues and costs.
- **Annexes:** (A1) An overview of WACC parameters and the calculations for converting nominal into real parameters; (A2) country fact sheets providing detailed regulatory data for each country; (A3) glossary of terms; (A4) the questionnaire issued to participants.

In each section, we describe the regulatory concepts, and we present data on the approaches adopted in practice by ERRA members. For major elements of the regulatory regime, this is accompanied by an evaluation of the regulatory practice of member organisations (MOs), analysing their approaches and providing commentary based on

[2] This designation is without prejudice to positions on status and is in line with UNSCR 1244 and the ICJ Opinion on the Kosovo Declaration of Independence.

international practice. The purpose is to provide commentary on why different approaches may have been chosen for the respective regulatory aspect, and their associated advantages and drawbacks, with a view to identifying the circumstances where these might be most appropriate, and to highlight key lessons that might emerge. In addition, **the report contains a set of seven boxes showcasing regulatory issues for current regulatory practice and providing suggestions for possible further development**.

The report concludes with some overall observations and learnings from the study – **Section 6 (Conclusions)**.

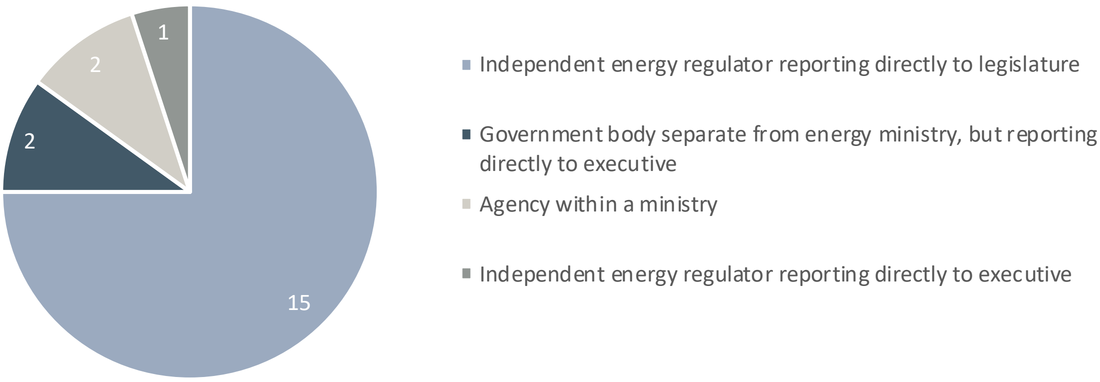
2 Regulatory governance

2.1 Governance and accountability

Regulators must determine tariffs that balance two conflicting goals: affordability for end users and financial sustainability for the regulated entity. Generally, it is in a government's short-term interest to secure lower tariffs, given that voters tend to place greater weight on the immediate priority of lower tariffs than the long-term importance of sustainable utilities. For this reason, **independence from government is often considered important for regulators to make well-balanced decisions**.

In the ERRA sample, **most regulators are fully independent from government, reporting directly to the legislature** (15) (see Figure 2). Two are quasi-independent, operating as a government body separate from the energy ministry, but reporting to the executive (Peru and Pakistan). Two operate as an agency within a ministry: Estonia within the Ministry of Justice, and Azerbaijan under the Ministry of Energy. Austria has an independent energy regulator reporting directly to the executive.

Figure 2 Independence of regulatory authorities



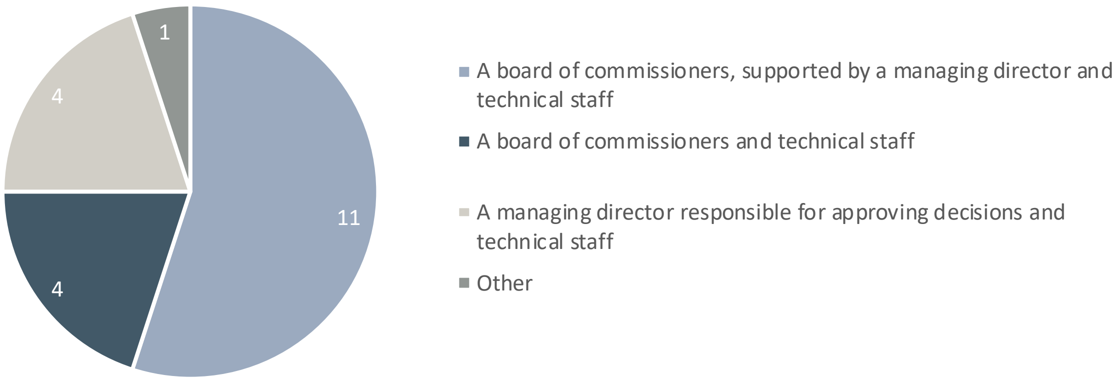
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Independent regulator reporting to legislature	✓			✓	✓		✓	✓	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓
Government body separate from energy ministry, but reporting to executive															✓	✓				
Agency within a ministry			✓			✓														
Independent regulator reporting directly to executive		✓																		

Source: Survey question 1.1. †See Footnote 2.

It is equally **important for regulatory staff with decision-making powers to be impartial**. Regulators with a concentration of decision-making power in a small number of agents, or even in the hands of one managing director, are more vulnerable to external influence.

In the ERRA sample, **most regulatory authorities are structured as a board of commissioners, supported by a managing director and technical staff** (11), meaning power is dispersed in these authorities (see Figure 3). Four authorities have a board of commissioners and technical staff. Four concentrate regulatory decisions in a managing director alone. Austria's regulator consists of four bodies: an Executive Board with two members; a Regulatory Commission with five members and five alternates; a Supervisory Board with four members; and a Regulatory Advisory Council with representatives of federal states, social partners, and associations.

Figure 3 Concentration of power within regulatory authorities



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
A board of commission-ers, supported by a managing director and technical staff	✓			✓			✓		✓	✓	✓			✓	✓	✓			✓	✓
A board of commission-ers and technical staff			✓		✓							✓	✓							
A managing director responsible for approving decisions and technical staff						✓		✓									✓	✓		
Other		✓																		

Source: Survey question 1.2. †See Footnote 2.

Similarly, if the government appoints the decision makers to a regulatory authority, there might be concerns that the incentives of these agents lean too heavily towards affordability in order to give the government a short-term popularity boost, rather than the financial sustainability of the utility.

In the ERRA sample, **commissioners are most commonly proposed and appointed by the executive (nine)** (see Figure 4). This means the energy minister or the national or regional governments propose and appoint commissioners.[3] In five authorities, commissioners are proposed by the executive and appointed by the legislature.[4] In four authorities, the legislature has full responsibility for proposing and appointing commissioners through an open call. In Estonia, commissioners are proposed by the civil service through an open call and appointed by the executive. In North Macedonia, an independent commission proposes the commissioners following an open call from government, and the legislature ultimately appoints them.

Figure 4 Independence of regulatory decision makers

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Proposed and appointed by executive		✓	✓		✓			✓							✓	✓	✓	✓	✓	
Proposed by executive and appointed by legislature							✓		✓	✓			✓							✓
Proposed and appointed by legislature through an open call	✓			✓							✓			✓						
Proposed by civil service via open call, appointed by executive						✓														
Proposed by independent commission via open call by executive and appointed by legislature												✓								

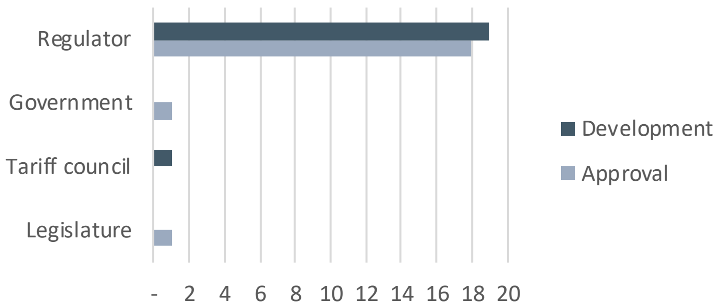
Source: Survey question 1.3. †See Footnote 2.

[3] In Peru, commissioners are appointed by the Council of Ministers, the Ministries of Economy / Finance and Energy / Mines, and the Competition Authority.
[4] In Lithuania, the members of the Board are appointed and dismissed by the legislature based on the proposal of the President of the Republic of Lithuania.

For a regulator to be institutionally independent from government, it is also important that it has **independence in developing the secondary legislation outlining the allowed revenue methodology**. A further step is to ensure they ultimately approve this methodology.

In the ERRA sample, **the regulator develops the allowed revenue methodology in 19 jurisdictions** (see Figure 5).[5] In Azerbaijan, a Tariff Council separate from the regulatory authority develops the methodology. **In 18 jurisdictions, the regulator ultimately approves the methodology**. In Bulgaria, the legislature approves the methodology. Only Azerbaijan reports that the government approves the allowed revenue methodology. However, the Regulatory Agency informs us that the strategy of Azerbaijan Government will empower the Agency to create its own methodology in future.

Figure 5 Developing and approving the allowed revenue methodologies



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Development																				
Regulator	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Tariff Council			✓																	
Approval																				
Regulator	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Government			✓																	
Legislature				✓																

Source: Survey questions 1.4 and 1.5. †See Footnote 2.

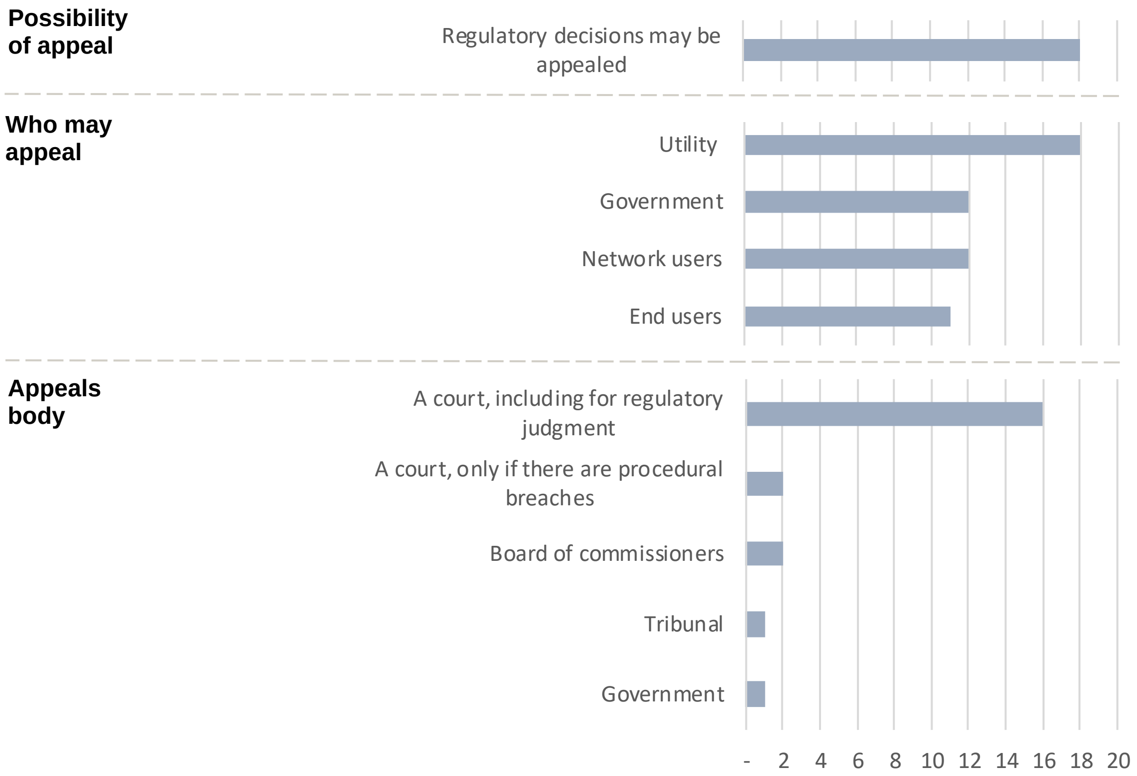
Another means of reducing the influence of the executive in regulatory matters is to give a degree of authority to an appeals body. If the judiciary is fully independent from government, courts might be best to take these appeals. However, other independent bodies, such as competition authorities, are also nominated as the appeal body in some countries, given the specialised nature of revenue determinations. **The appeals body ultimately holds the regulator to account for its decisions**.

[5] In Austria, while the regulator develops the methodology, utilities and organisations have the opportunity to comment. Organisations include the Federal Economic Chamber, the Federal Chamber of Agriculture, the Federal Chamber of Labour, and the Trade Union Federation.

In the ERRA sample, **regulatory decisions may be appealed in 18 jurisdictions** (see Figure 6).[6] The exceptions are Czechia and Hungary, where this is not possible. In all jurisdictions with a right of appeal, the utility may appeal. In 12, the government and network users may also appeal. In 11, end users may appeal.

In the ERRA sample, **in all jurisdictions with a right of appeal, courts are to some extent an appeals body**. In 16, this includes regulatory judgement. In two jurisdictions, courts may only receive appeals concerning procedural breach. In addition to courts, Slovakia and Nigeria include a specialist board of commissioners in the appeals process. In Slovakia, this board is the first-instance appeals body, whose decisions are subject to review by courts. In Azerbaijan, regulatory decisions can alternatively be appealed through an administrative procedure via the government; the first instance in this procedure is the Commission of Appeal under the Ministry of Energy, and the second instance is the Commission of Appeal under the Presidential Office. In Pakistan, appeals can be made either in court or at a tribunal. In Lithuania, the Competition Authority has the right to investigate and give the instruction to amend or repeal the decision of the energy regulatory authority.

Figure 6 Appealing regulatory decisions



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Possibility of appeal																				
Can regulatory	✓	✓	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

[6] The table only summarises the ability of four key actors to appeal (end users, network users, the government, and the utility), but in many cases, other actors may appeal. For example, in Austria, the Federal Economic Chamber and Federal Chamber of Labour may also appeal.

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
decisions be appealed?																				
Who may appeal*																				
Utility	✓	✓	✓	✓		✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Government	✓		✓			✓	✓		✓	✓	✓	✓	✓			✓			✓	✓
Network users	✓			✓		✓	✓		✓	✓	✓	✓	✓			✓			✓	✓
End users	✓					✓	✓		✓	✓	✓	✓	✓			✓			✓	✓
Appeals body																				
A court, including for regulatory judgment	✓	✓	✓	✓		✓	✓		✓	✓	✓	✓		✓		✓	✓	✓	✓	✓
A court, only for procedural breaches													✓		✓					
Board of commission-ers													✓					✓		
Tribunal																✓				
Government			✓																	

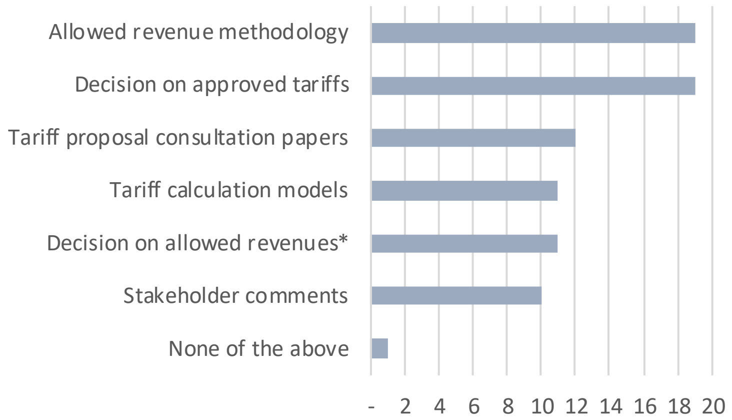
Source: Survey question 1.10 to 1.12. †See Footnote 2.*The table does not provide an exhaustive list of who may appeal, but an overview of whether the key actors listed may appeal.

2.2 Transparency

Regulatory transparency in the determination of allowed revenues is important for the regulator to build trust with end users who pay the tariff and the regulated entities who need tariff revenues to cover their costs. Transparency also allows for methodological scrutiny, which ultimately leads to better practice and reduces the likelihood of corruption.

In the ERRA sample, most respondents make their allowed revenue methodology publicly available (19) (see Figure 7). Only Azerbaijan indicates that its methodology is only available to utilities. Nineteen respondents publish their decision on the approved tariffs. Azerbaijan is the exception. Twelve make their tariff proposal consultation papers public. Eleven publicise their tariff calculation models and decisions on allowed revenues. Only ten make stakeholder comments publicly available.

Figure 7 Public availability of allowed revenue and tariff documents



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Allowed revenue methodology	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Decision on approved tariffs	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Tariff proposal consultation papers				✓	✓		✓		✓	✓	✓	✓	✓		✓	✓		✓		✓
Tariff calculation models	✓	✓				✓	✓		✓		✓		✓		✓		✓	✓	✓	
Decision on allowed revenues*	✓			✓			✓		✓	✓		✓	✓		✓	✓			✓	✓
Stakeholder comments on determination				✓	✓		✓		✓	✓			✓		✓	✓		✓		✓
None of the above			✓																	

Source: Survey questions 1.6 and 1.7. †See Footnote 2. *If applicable.

Also important is transparency in the regulatory accounts of the regulated entities. Regulation is informationally demanding, and it is important that regulators can obtain robust and reliable information on business costs. Accordingly, it is common in many frameworks to compel the auditing of the regulated entities' accounts.

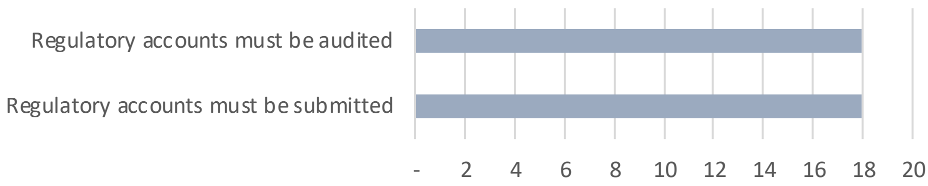
In the ERRA sample, 18 regulatory authorities require the auditing of regulatory accounting statements (see Figure 8).[7] Only in Hungary and North Macedonia is this not a binding requirement.[8] Eighteen regulatory authorities require the regulatory accounting statements to be submitted. Only in Estonia and Georgia is this not a legal requirement.

[7] We allow this to be interpreted in two ways: (i) the requirement that a utility submit separate regulatory statements that are audited, or (ii) that a regulator uses previously audited figures from the statutory accounts to calculate tariffs.

[8] In Hungary, the unbundled balance sheet and profit and loss account are subject to an audit, but other required accounts and documents are not.

However, while not compelled to submit the actual accounts, utilities in Estonia must submit data based on the accounts. Georgia's energy regulator informs us they have already approved a legal requirement for TSOs and DSOs to submit regulatory accounting statements from 2021.

Figure 8 Accounting transparency of regulatory authorities



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Regulatory accounting statements subject to an audit?	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓
Submit regulatory accounting statements?	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

Source: Survey question 1.8 and 1.9. †See Footnote 2.

2.3 Observations on governance

All MO countries have taken steps to create some degree of independence for their regulators. As mentioned above, greater independence is generally considered important so that tariff-setting is not subject to short term and opportunistic decision-making. In other words, **independence is considered necessary for ensuring that regulation is predictable and consistent with the long-term interests of both network users and investors** or the owners of the regulated entities.

As shown in the preceding sections, the form of governance chosen by the MO countries differs, presumably reflecting explicit policy choices but also the specific institutional characteristics of the relevant countries, as well as the stage of more general electricity sector reform. As a result, the degree of independence of the regulators differs across the sample countries; whether this differentiation has a material impact on the effectiveness or the quality of regulation that is exercised in each case cannot be easily ascertained in an objective manner.

Nevertheless, it is worth emphasising that **effective governance of the tariff-setting process requires more than the establishment of independent or semi-autonomous regulators and regulatory rules** (ie it might be a necessary but it is not a sufficient condition); it also requires scrutiny of the forecasts, assessments and proposals submitted by the regulated companies, and the **exercise of significant judgement by regulators** in determining whether and to what extent these are justifiable. Hence, beyond independence *per se*, it is important that **duties and powers are sufficiently defined to**

ensure predictability, objectivity, transparency and accountability in the exercise of the necessary judgement involved with tariff regulation. Such duties generally require regulators to have the authority to:

- request and procure information and carry out investigations;
- oblige the regulated entities to consult with interested parties in respect of any investment or other change to their assets, service levels or methods of operation that could have a material effect on their interests;
- specify requirements for the regulated entities to make and, where appropriate, publish regular and *ad hoc* reports to the regulator;
- seek explanations and an evidence basis for any forecast of costs, revenues, outputs (including service levels) and any assessment of risk, market conditions, asset conditions and any other factor relevant for the scrutiny of tariff proposals in accordance with regulatory rules;
- specify adjustments to forecasts and assessments supporting tariff proposals where material, subject to an obligation on the regulator to consult with interested parties on any such adjustment; and
- enforce compliance with the relevant rules and licences, and levy penalties in the event of non-compliance.

Whether MO regulators have these powers was not explored in the study questionnaire, so these functions may or may not already be vested in the MO regulatory agencies. The above, nevertheless, serve as a useful reminder of the types of arrangements needed for **ensuring that regulators (whether fully independent or not) exercise judgement within well-defined rules**.

3 Overall tariff framework

3.1 Tariff regulation methods

The 'tariff regulation method' is the broad approach adopted by the regulator to control the regulated entity's tariffs. The approaches differ according to:

- **forecasts *vs* actual costs:** whether the regulator bases its decision on forecasts of the entity's costs (which may nevertheless be assessed by having regard to outturn costs) or solely based on its historical or actual costs;
- **regularity of reviews:** whether reviews are requested by the entity or regulator at their discretion, or whether they are held at pre-determined times.

Some common methods include *rate-of-return*, *cost-plus*, *revenue cap*, and *price cap* (see Table 2). In practice, regulators often employ mixed approaches or apply variations to these regimes.

Table 2 Tariff regulation methods

Regime	Description
Rate of return	▪ Revenues set to equal *historical* costs. ▪ Reviews held at the request of the utility or regulator, as required, to maintain a reasonable allowed return.
Cost plus	▪ Revenues set to equal *actual* costs. ▪ Reviews scheduled frequently (eg annually, or more often) to ensure tariffs track realised costs.
Revenue cap	▪ Revenues determined based on *forecast* costs. ▪ Reviews held at regular multi-year intervals, which set the utility's allowed revenues *ex-ante* for each year leading up to the next review. ▪ The utility may typically (although not necessarily) price its services as it wishes, provided that revenues do not exceed the cap.
Price cap	▪ Revenues determined based on *forecast* costs. ▪ Review held at regular multi-year intervals, which set an allowed average tariff for a basket of the utility's goods and services for each year leading up to the next review. ▪ The utility may typically price its services as it wishes, provided that, for a defined basket, the average tariff does not exceed the cap.

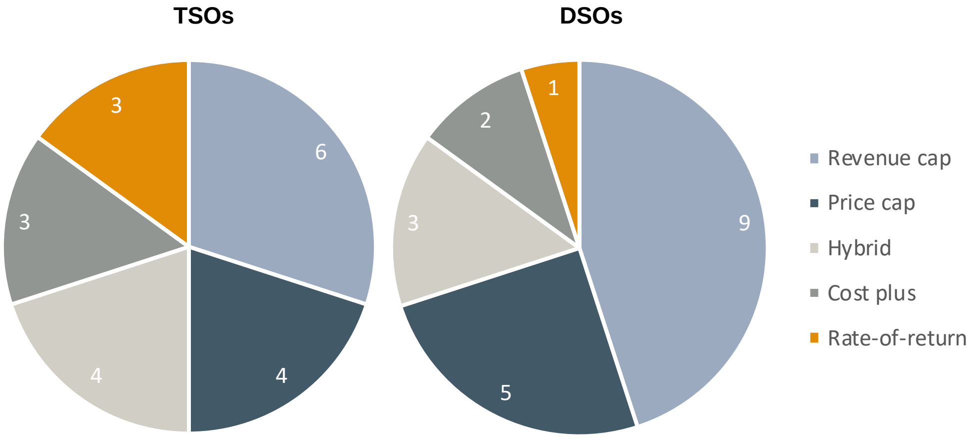
Source: ECA

In the ERRA sample, **the most common approach is revenue cap** (six TSOs and nine DSOs[9]), followed by price cap (four/five), hybrid (four/three), cost plus (three/two), and rate-of-return (three/one) (see Figure 9). **In most cases, the TSO and DSO use the same tariff regulation method**, except for Austria, Bulgaria, Peru, and Poland. For the DSO, Poland uses a revenue cap. For the TSO, it uses a hybrid of the revenue cap and cost-plus. Pakistan also uses a hybrid approach for its TSO and DSO. This hybrid approach

[9] That is to say six TSO and nine DSO regulatory regimes. Throughout the report, whenever there is a number of TSOs/DSOs with relation to any quoted statistics, it refers to a number of TSO or DSO regulatory regimes, rather than particular operators.

combines rate of return for capex with elements of a revenue cap for opex. Hungary's hybrid approach combines a revenue and price cap; the tariffs are capped, but there is a correction if actual revenue differs more than 2% from the required revenue.

Figure 9 Tariff regulation methods



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Revenue cap					✓		✓				✓	✓		✓					✓	
Price cap	✓								✓				✓					✓		
Hybrid								✓								✓	✓			✓*
Cost plus		✓	✓							✓										
Rate-of-return				✓		✓									✓					
DSO																				
Revenue cap		✓		✓	✓		✓				✓	✓		✓			✓		✓	
Price cap	✓								✓				✓		✓			✓		
Hybrid								✓								✓				✓*
Cost plus			✓							✓										
Rate-of-return						✓														

Source: Survey question 2.1. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. *This is how Kosovo characterises its regime, although from our understanding it resembles more a revenue cap. For example, both opex and capex are set *ex-ante*, the utilities bear the losses of overspending and tariffs are adjusted to account for differences between forecast and realised volumes.

3.2 Observations on tariff regulation methods

As demonstrated above, incentive-based regimes (revenue and price caps) are used more commonly than rate-of-return or cost-plus regimes among the MOs. The main trade-off[10] between these two broad sets of tariff regulation methods is the **balance between the risk to the regulated entity of not recovering its costs and the incentives for productive efficiency**.

Incentive regulation is generally thought to provide stronger incentives for efficiency, as the regulated entity retains all (or part of the) cost savings it makes for some time, usually the duration of the regulatory period, after which the future benefit of these savings is passed on to network users through reduced cost allowances and therefore tariffs.

In contrast, under rate of return regulation, the divergence between costs and revenues would trigger a review, with the regulated entity only keeping the saving for the time it takes to conduct the review. This 'regulatory lag' means there are some incentives for efficiency under rate of return regulation, but they are muted compared to incentive regulation. In the cost-plus model, where reviews occur annually or more frequently, there is little if any incentive for cost efficiency. Box 1, below, contains more information about the efficiency incentives associated with the various regulation regimes.

This efficiency incentive, however, involves a trade-off with risk to the regulated business of not recovering its costs. Under rate of return regulation, if a business' costs increase, it can seek a review and its revenues will be brought back in line with costs, albeit potentially subject to a slight lag and (potentially) a review to ensure the costs were prudently incurred. In contrast, a regulated business subject to incentive regulation, must bear (all or a portion of) cost increases for the duration of the regulatory period. The risk of a regulated business not recovering its costs is, therefore, greater under incentive regulation. This trade-off is illustrated in Table 3, below (note that hybrid schemes display elements of these regimes depending on the mix of approaches employed).

Table 3 Risk/reward trade-off under different tariff regulation methods

Regulation method:	Cost-plus	Rate-of-return	Revenue/price cap
Risk that the business will not recover its costs	Low	Medium	High
Incentives for the business to improve efficiency	Low	Medium	High

Source: ECA

The choice of the preferred method of regulation therefore is not unambiguous and depends on both country circumstances and the relative weighting placed on different objectives. **Most MOs in this study seemingly place greater emphasis on efficiency incentives, given the prevalence of incentive-based regimes**.

Moreover, **revenue (rather than price) caps predominate for both transmission and distribution, which means the risk of higher or lower tariffs due to demand differing**

[10] There are other trade-offs too, for example, regarding the simplicity and transparency of the different regulatory methods, and the level of predictability associated with them.

from forecast is borne by network users. This also appears to be consistent with efficiency objectives, given that, provided the demand forecasts are not grossly mis-specified, the costs of the electricity transmission and distribution networks will vary only slightly with demand.

Box 1 Efficiency incentives under different tariff regulation methods

Revenue cap regimes are believed to generally provide **strong incentives for operating cost reductions**, given that (subject to any sharing mechanisms) revenues are fixed and therefore the higher the reduction in costs, the higher are the profits of the regulated company. This is generally the case for price caps too (and to a lesser degree to the hybrid systems) but contrasts the cost-plus regimes where efficiency incentives are muted given that any cost reductions are passed through to customers and therefore do not improve company profitability.

Also, a revenue cap ensures the network businesses a particular level of revenue, irrespective of demand. This should therefore lower the cost of capital to the regulated entities, relative to a price cap, although it would still be higher relative to a cost-plus or rate of return regime. However, it is unclear whether this theoretical advantage of revenue cap regimes translates into a lower cost of capital in practice.

Whether the above efficiency incentives apply to **investments and innovations over time** is even more contentious. In the case of revenue-cap regimes, there is arguably an incentive to delay investments, especially those associated with quality improvements or service expansions – this is because revenue remains the same irrespective of demand, so the latter does not determine total revenue and profits. In the case of price caps, investment and innovation incentives might also be lower if these lead to reductions in throughput (and therefore future revenues/profits). Cost-plus regimes, on the other hand, might result in the opposite problem, that is, of 'gold-plated' investments (ie over-investment in network capacity).

Where expanded service coverage is important, therefore, revenue caps might not be the preferred option and cost-plus or rate of return regimes might be favoured instead. Price caps may also be preferred as these provide incentives for network business to meet and expand demand since demand increases result in additional revenues (whereas they are fixed under a revenue cap regime). Hence, provided the incremental cost of expanding capacity is lower than the revenue associated with the expanded service coverage, the network businesses will have the incentive to meet demand.

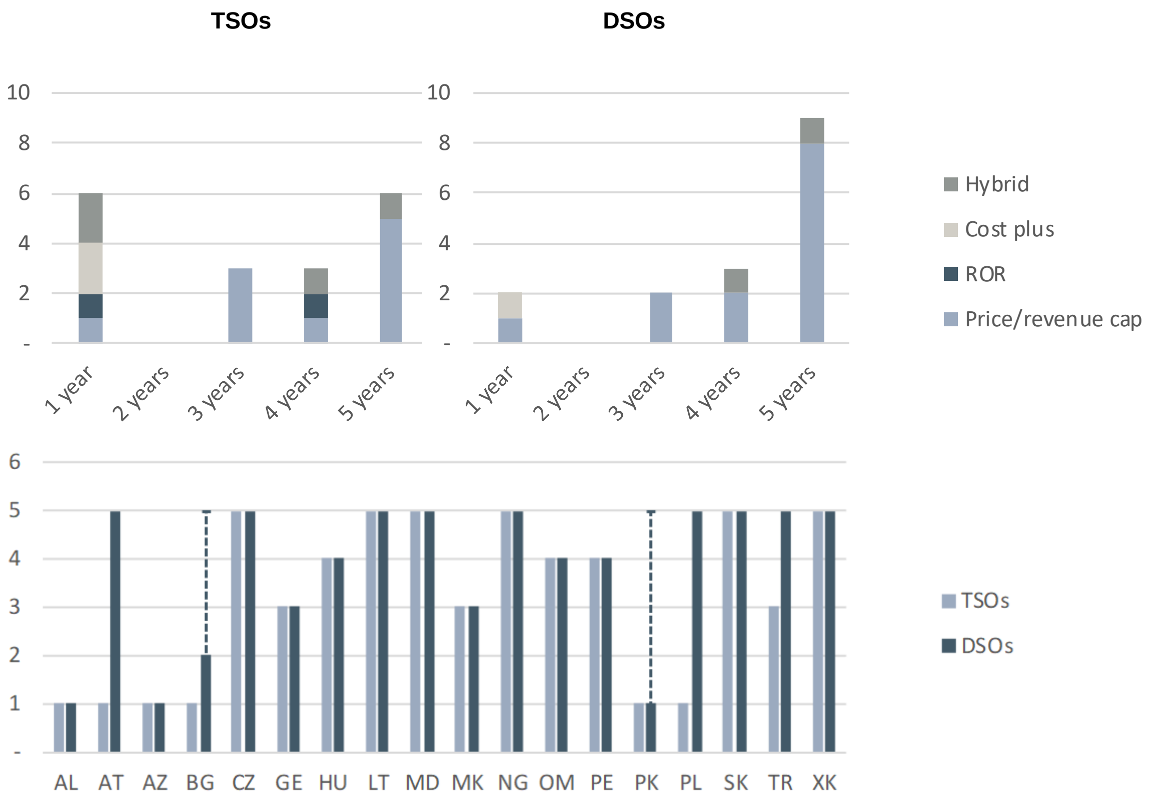
3.3 Length of regulatory period

In a price- or revenue-cap regime, the duration between reviews determines how long the cap applies. In some cases, the duration of the cap is decided upon completion of the review. Alternatively, the duration of the cap can be fixed in law.

Conflicting cases can be made on the best duration. A longer duration reduces the burden on the regulator and utility, as work-intensive reviews become less frequent. Additionally, a longer duration strengthens the incentive for utilities to outperform *ex-ante* cost assumptions through the potential to make large profits. However, there is also greater potential to make large losses if utilities consistently surpass expected costs.

In the ERRA sample, the reported lengths of the regulatory periods are displayed in Figure 10. Two countries vary the length of the regulatory period across DSOs; Pakistan's DSO regulatory period is one year for seven DSOs and five years for three DSOs, and Bulgaria's DSO regulatory period ranges from two to five years. Some other countries have a different regulatory period for the TSO and DSO; in Turkey, the revenue cap is three years for the TSO, and five years for the DSO, and Austria and Poland have five-year revenue caps for their DSOs but one-year regimes for their TSOs. All cost-plus regimes have a regulatory period of one year.

Figure 10 Length of regulatory periods



Source: Survey question 2.4. Pakistan's DSO regulatory period is one year for seven DSOs and five years for three DSOs. Bulgaria's DSO regulatory period ranges from two to five years. For simplicity, we exclude Bulgaria and Pakistan from the top two charts, but they are included in the bottom chart.

While the regulatory period is often fixed in applicable regimes, laws typically contain clauses that allow premature tariff or revenue resets in exceptional circumstances. Such circumstances could include large or unforeseen cost shocks or other material events or changes. **These are referred to as *tariff resets* or *re-openers***. The formal predetermined triggers or materiality thresholds may be specified in detail in law, although this is often left open to the interpretation of the regulator.

In the ERRA sample, **11 TSOs and 12 DSOs permit such re-openers**. Eight of the ten TSOs and 11 of the 14 DSOs with a revenue or price cap allow re-openers, while no TSOs or DSOs with a cost-plus regime allow re-openers. Albania, Turkey and Peru are the only price or revenue caps that do not permit re-openers. For those with a rate-of-return regime, they are permitted to request a tariff review at their discretion, so re-openers are irrelevant. Some of the triggers for a re-opener are outlined in Table 4.

Table 4 Re-opener triggers

Country	Pre-determined trigger for re-opener
Bulgaria	▪ Legislative changes ▪ Deviation in the market price by ±5%
Czechia	▪ Legislative changes related to a licensed activity

Country	Pre-determined trigger for re-opener
	▪ Exceptional changes to electricity market or national economy ▪ Parameters were determined based on incorrect, incomplete, or false data
Georgia	▪ For a given tariff year, correction factor exceeds ±10% of allowed revenue
Kosovo†	▪ Force majeure ▪ Materiality threshold, excess of 5% of the Maximum Allowed Revenues
Lithuania	▪ Strategic projects needed
Moldova	▪ For a given tariff year, correction factor exceeds ±5% of allowed revenue
Nigeria*	▪ 'Exceptional changes' to the electricity market or national economy ▪ Inflation rate, foreign exchange rate, or generation capacity change by ±5%
Oman	▪ An uncontrollable cost shock that has led the company to be unfinanceable
North Macedonia	▪ Trigger not specified, but re-openers permitted
Slovakia	▪ 'Significant change' of economic parameters applied in tariff determination

Source: Survey question 2.5. †See Footnote 2. *These are triggers for a bi-annual minor review

3.4 Observations on the duration of the regulatory period

The MO experience accords with that of regulatory regimes elsewhere, that is, regulatory agencies employing incentive regimes appear to have **largely settled on a three to five-year regulatory period** as representing an appropriate balance between not imposing excessive risk on regulated utilities (or network users), while avoiding too frequent resetting of tariff controls.

In many of the MOs, the regulatory period has been recently extended (or is planned to be for the next regulatory period), presumably with a view to further minimising the cost of regulation and providing stronger incentives for efficient operation. At the same time, **many of the regulatory agencies adopt several mechanisms to mitigate against the risk of excessive profits or losses that might be earned or incurred when regulatory periods are longer**, such as:

- the ability to reset allowed revenues within the regulatory period if material changes occur or if unanticipated investment arises (as discussed above);
- treating 'uncontrollable' operating costs as pass-through (see Section 4.1.5) *and* allowing adjustments for these within the regulatory period; and
- annual adjustments to individual tariff levels to account for deviations between forecasted and realised volumes (in the case of some revenue cap regimes).

Nevertheless, **in some circumstances, it may be appropriate to specify shorter regulatory periods**, such as:

- when the regulation method is focused more on ensuring cost recovery (that is why the cost-plus models generally have an annual or shorter regulatory cycle) and that tariffs closely track costs;

- if sector regulation has only been introduced relatively recently and therefore the regulator and the network businesses are still gaining experience with operating under a multi-year regulatory regime; and

- where there is relative paucity of information for effectively scrutinising the costs of the network service providers.

3.5 Determination of revenue requirement

The tariff regimes described in Table 2 set the revenue requirement based on actual or forecast total costs. **Distinct approaches can be used to determine what are the utility's total costs, and hence what should be the revenue requirement, including *building-blocks*, *accounting*, *cash-based*, *totex*, and others** (see Table 5).

Table 5 Methods for determining revenue requirement

Method	Description
Building blocks	▪ Revenue requirement is the sum of individual costs - return on capital, return of capital (ie depreciation), operating costs ▪ Typically paired with price- or revenue-cap regimes, meaning *ex-ante* costs are usually employed in this method ▪ Capital costs (capex) and operating costs (opex) are treated separately ▪ Applied by numerous regulators in Europe and Australasia (although not always by this name)
Accounting	▪ Revenue requirement is closely linked to operating expenditure, depreciation and interest costs that appear in statutory accounts / financial statements ▪ The cost of equity is generally set at a level that is considered 'fair', given the monopoly status of the utility, and capital expenditure is scrutinised for its prudency ▪ Applied by numerous regulators in the US
Cash-based	▪ Focuses solely on the cash outlays of the regulated entity, such as its debt repayments and interest costs ▪ Applied in many emerging countries that might be developing new markets and that have fast rates of growth in demand, high and (relatively) unpredictable investment needs, high debt servicing costs arising from those investments, and constraints on charging fully cost-reflective tariffs to customers due to affordability concerns
Totex	▪ Similar to the building-blocks approach, but capital and operating expenditure (capex and opex) are summed to produce total operating expenditure (totex), which is capped *ex-ante*

Source: ECA

In the ERRA sample, **regulatory regimes governing 19 TSOs and 18 DSOs use building blocks** to determine the revenue requirement (see Figure 9). The regulatory framework for the Peruvian DSO deviates from this, instead adopting a totex approach.[11] The Turkish regulator uses statutory accounts in the determination of the revenue requirement of the TSO, but only as a loose guide to assist the building-blocks approach.

---

[11] Based on our definition, the *Totex* approach is similar to the *Building Blocks* approach, but the capex and opex blocks are combined. Therefore, the regimes all adopt a broadly similar approach.

- **Real price adjustment** – this accounts for input (labour, materials, plant and equipment, etc) price changes. We note that in some regimes, allowed revenues are set in real terms (ie they are indexed to inflation). In this case, the adjustment would need to be estimated as the *differential* between input price inflation and economy-wide inflation (as measured usually by CPI).
- **Step changes** - the final element to consider is whether any extraordinary changes need to be added (or subtracted) for any other costs not captured in base opex or the rate of change (given by the product of the efficiency, productivity and real price factors), but which are necessary and prudent. These could arise from new regulatory obligations, for example, or significantly changed business circumstances and/or *force majeure* events.

4.1.3 Allowed versus actual opex

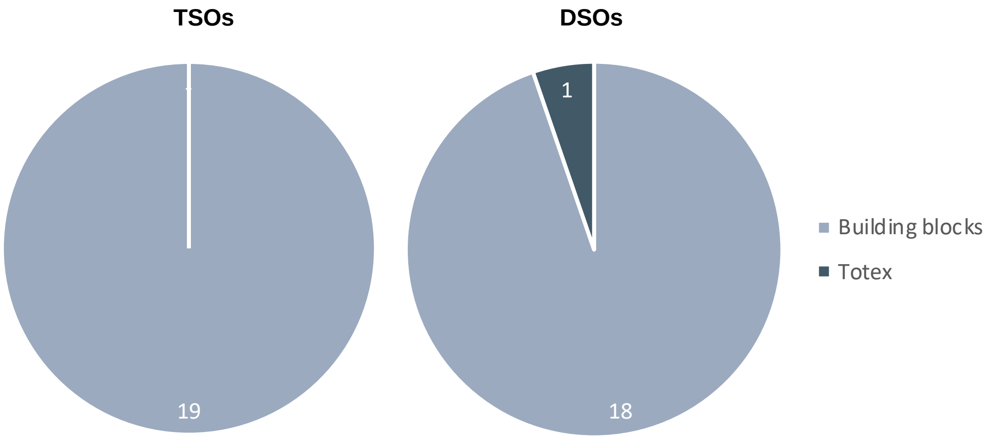
In a regime where the allowed opex is determined *ex-ante*, there will inevitably be deviations between the allowed and actual opex in the form of efficiency savings or losses. **The regulators have two broad options. One is for the utility to bear all savings or losses, ie no action is taken by the regulator. Another is for the utility to share savings or losses with network users**. The former provides the utility with a profit incentive to cut costs, but it places the utility at greater financial risk in the face of losses. The latter dilutes efficiency incentives, but also limits the losses/gains for the utility and its customers.

There are three approaches to sharing savings or losses between utility and customer:

- Share savings and losses symmetrically, eg if the utility keeps 70% of savings due to underspending, it must also bear 70% of losses due to overspending.
- Share only losses due to overspending, eg the utility keeps all savings from underspending, but customers must bear some of the losses due to utility overspending.
- Share only profits due to underspending.

In the ERRA sample, **in most cases the utility bears all savings and losses** (17 TSOs and 18 DSOs) (see Figure 13). This means that no adjustments to allowed revenues or opex allowances are made in the next period to compensate for a deviation from allowed opex in the current period. The only countries to make this adjustment are Albania and Kosovo for both the TSO and DSO, and Peru only for the TSO. Albania and Peru share the savings and overruns symmetrically, ie they make equivalent adjustments in the case of both savings and overruns. Kosovo *only* adjusts in the case of savings, meaning the utility bears the consequences of cost overruns without passing this on to the customer. Of the countries making adjustments, only Kosovo has a formally pre-determined sharing ratio of 50:50 between customer and utility (for cost savings). Albania and Peru determine the sharing ratio on a case-by-case basis.

Figure 11 Methods for determining revenue requirement



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Building blocks	✓	✓	✓	✓	✓	✓	✓	✓	✓	?	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
DSO																				
Building blocks	✓	✓	✓	✓	✓	✓	✓	✓	✓	?	✓	✓	✓	✓		✓	✓	✓	✓	✓
Totex										?					✓					

Source: Survey question 2.3. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): We were unable to find out how Latvia determines the TSO and DSO revenue requirement.

3.6 Observations on the revenue determination methods

Clearly, **the building block methodology is the most prevalent (and almost universal) method used for determining the reasonable costs** of network service providers and therefore calculating their allowed revenues. This is expected given the obligation on regulators to ensure cost recovery for the regulated entities. In this context, it is worth recalling that the building block model can be broadly represented mathematically with the following two equations – the revenue equation (1) and the asset base roll-forward equation (2):

$$\begin{aligned} REV &= OPEX + DEP + ROC + ADJ \\ &= OPEX + DEP + (WACC \times RAB) + ADJ \end{aligned} \quad (1)$$

and

$$RAB = RAB_{-1} + CAPEX - DEP \quad (2)$$

where REV is the regulated revenue requirement, $OPEX$ is operating and maintenance expenditure, DEP is depreciation, ROC is return on capital, ADJ is revenue adjustment, $WACC$ is the weighted average cost of capital, RAB is the regulatory asset base calculated for the current regulatory period, and $CAPEX$ is capital expenditure. RAB_{-1} is the regulatory asset base in the previous regulatory period.

Ignoring any revenue adjustments or incentive rewards and penalties, these equations together **ensure that the present value of the allowed revenue stream is equal to the present value of the expenditure stream of the regulated network service providers**.[12] This condition is known as the **financial capital maintenance** (FCM) principle, and is important for any regulatory regime.

Nevertheless, **if the regulated network service providers were always and fully compensated for their expenditure (as is the case under strict FCM) they would face no particular incentives to produce services of a given quality or to reduce their expenditure**. Incentive regulation, therefore, as practised in some MOs, entails deviation from the principle of FCM, but in principle only to the extent that it rewards or penalises the regulated firms for promoting desirable objectives. Much fewer MOs (and regulators elsewhere), however, adopt 'totex' approaches, where allowed revenues are determined by combining operating and capital expenditures. Totex is likely to feature more prominently in future, especially as capex and opex become more substitutable with the required evolution of energy networks to manage distributed generation, intermittent demand, bi-directional power flows, batteries and storage, electric vehicles, etc (see Box 2, below).

Box 2 Totex approach to regulation

Totex approaches to regulation assess capital and operating expenditure in combination (particularly as these are often substitutable and/or the level of spending on one category affects the other). That is, the regulatory focus in such regimes is on total and lifecycle costs. Three key considerations motivate the use of a totex approach:

1. **Removal of the 'capex bias'** – it is generally felt that building block approaches favour capital expenditure solutions (eg asset replacement) over opex (ongoing maintenance), as the former would provide a steady stream of profits over the assumed life of the assets. This bias is more pronounced where there is an incentive mechanism applied to opex underspending (as the firm also retains the savings on opex, or a portion of them, as a reward for its outperformance).
2. **Potential gaming by the regulated firm** - the conventional building block approach may also provide a perverse incentive to reclassify opex as capex – a regulated firm, for example, would gain by having a category of expenditure recognised as opex when setting allowances and then changing its capitalisation policy within the regulatory period to reclassify the expense as capital expenditure.
3. **Business flexibility for efficient delivery of services** – under a totex approach the regulator adopts a neutral view about whether operating or capital expenditures should be incurred, which should then encourage the regulated businesses to choose the mix of expenditure that is most consistent with long-term efficiency.

Regulatory frameworks employing totex approaches rely heavily on statistical benchmarking techniques for establishing the cost of service. They therefore do create greater complexity and add cost, which should not be under-estimated; indeed, this might largely explain why totex has not been adopted more widely. For example, the results are often sensitive to data errors, statistical assumptions and variable (potentially subjective) modelling choices. If the results of the analysis are to be robust, it also requires a large number of comparator businesses. For this reason, totex and benchmarking has advanced furthest in the regulation of electricity distribution in countries where multiple distributors exist (for example, in Germany and Sweden, which literally have hundreds of distributors).

[12] For this condition to hold, the allowed WACC must equal the true cost of capital of the business.

3.7 Efficiency factors

In revenue- or price-cap regimes, which determine allowed revenues based on forecast costs, the regulator could assume efficiency improvements over time. **A common approach is to allow the cap to grow in line with CPI-X, where CPI is the inflation rate (consumer price index), and X is an efficiency factor**.

Rate-of-return and cost-plus regimes, which determine allowed revenues based on actual costs, do not usually incorporate an *X-efficiency factor*. For this reason, they are often criticised for not incentivising efficiency gains, although they place less financial risk on utilities.

In the ERRA sample, only four of the ten TSOs and six of the 14 DSOs with a price or revenue cap have an *X-efficiency factor*. The factors reported for these countries are listed in Table 6.

Table 6 X-efficiency factors

Country	TSO	DSO
Albania	0%*	0%*
Austria		0.95%
Kosovo†	1.5%	1.5%
Moldova	1%	1%
Oman	-2%	-2%
Pakistan		0% - 5.8%**
Slovakia	3.5%	3.5%
Turkey		0% - 11.15%**

Source: Survey question 2.2. †See Footnote 2. *The regulatory rules foresee the use of an efficiency factor based on TSO benchmarking and information furnished by TSO, but this is still pending. Therefore, the factor has been set to zero in the interim. **Differs across DSOs.

In addition to a general *X-efficiency* factor on the overall price or revenue cap, **efficiency improvements can be assumed in individual allowed expenditures** (eg opex and capex) under a building-blocks regime; this is discussed in Section 4, including a discussion on how efficiency factors could be determined in Section 4.1.7.

4 Cost and revenue determination

4.1 Opex

4.1.1 Determination of allowed opex

The allowed **operating expenditure (opex) is typically determined based on one, or a mix, of four broad approaches: *bottom-up*, *top-down*, *yardstick*, or *historical outturn opex*** (see Table 7). Some regulators adopt a *totex* approach, in which they determine instead an allowed total expenditure (totex) that encompasses both opex and capital expenditure (capex).[13]

Table 7 Methods for determining allowed opex

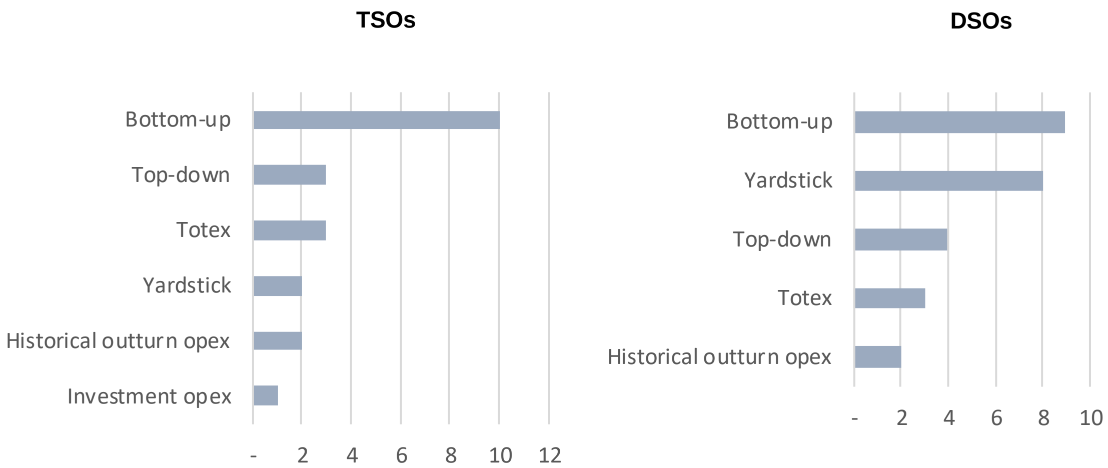
Method	Description
Bottom-up	▪ Regulator determines an allowed operating expenditure (opex) for individual opex items proposed by the utility. These are summed to produced total allowed opex. ▪ Determination of efficient cost of each opex item is usually based on audited financial statements, historical trends, statistical analysis, etc.
Top-down	▪ Regulator determines an allowed cost for broad opex categories. These are summed to produce total allowed opex. ▪ Determination of an efficient cost for each opex category is often informed by external comparators, but the regulator exercises discretion.
Yardstick	▪ Allowed opex determined using an external benchmark, ie using costs of other utilities. ▪ Distinct from top-down approach, in which external comparators merely *inform* the regulator.
Historical outturn opex	▪ Allowed opex determined using an internal benchmark, ie using the utility's own previous total opex. ▪ Regulator sets future opex at levels commensurate with past efficient opex, adjusting for extraordinary costs, inflation and network growth. ▪ Distinct from bottom-up approach, in which previous individual opex items may guide current maximum opex for those items.
Totex	▪ The allowed opex is assessed together with allowed capex, usually employing benchmarking and statistical analysis.

Source: ECA

In the ERRA sample, **the most common approach for determining allowed opex for TSOs and DSOs is bottom-up** (ten TSOs and nine DSOs) (see Figure 12). For TSOs, the other approaches, in order of popularity, are top-down (three), yardstick (two), and historical outturn opex (two). One TSO employs what we have termed 'investment opex', which calculates expenditure as a percentage of investment costs. For DSOs, the other approaches are yardstick (eight), top-down (four), and historical outturn opex (two). Three countries determine totex rather than opex.

[13] See a discussion on totex in Box 2 on page 22.

Figure 12 Methods for determining allowed opex



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Bottom-up	✓					✓	✓	✓		✓	✓		✓	✓		✓	✓			
Top-down									✓			✓						✓		
Totex		✓	✓	✓																
Yardstick													✓							✓
Historical outturn opex					✓														✓	
Investment opex															✓					
DSO																				
Bottom-up	✓						✓	✓		✓	✓		✓	✓		✓	✓			
Top-down									✓			✓		✓				✓		
Totex		✓	✓	✓																
Yardstick						✓		✓					✓	✓	✓	✓			✓	✓
Historical outturn opex					✓														✓	

Source: Survey question 3.1. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

4.1.2 Observations on opex cost assessment methods

Bottom-up assessments are the most common cost assessment approach for opex among the MOs. This is not entirely surprising, particularly as some of the regimes are fairly new and this is how all regulators start, given that **a deep understanding of the regulated entities' business and the companies' own models, data and methodologies is needed before cost submissions can be challenged by the regulator and/or insights or evidence from comparator businesses can be used**. There are also distinct advantages to using this approach:

- It is generally **less data intensive** - the emphasis on looking at individual cost items means there is much less need than under other approaches to obtain a full set of comparator data.

- It might be **more acceptable to the regulated entities and network users**, because there is more emphasis on reviewing the costs of the utility itself, rather than external comparators, and it uses much simpler comparisons than the complex statistical analysis required, for example, if benchmarking costs against other network businesses.

Nevertheless, it must also be recognised that there are disadvantages with bottom-up assessments, chief amongst which is an **inordinate focus on individual cost items** rather than considering the overall costs and revenue requirements. This may **remove incentives to flexibly manage expenditure and exploit opex substitution possibilities** to minimise cost. This is also why some regulators combine bottom-up cost reviews with other assessment methods – for example, Oman also uses top-down and yardstick comparisons for its DSO, while Hungary, Nigeria and Pakistan employ yardstick comparisons with their bottom-up assessments for DSOs. This combined approach can be useful for regulators to 'sense check' their assessments – the fact that external benchmarks are used to *inform* decisions on efficient costs rather than purely *relying* on these for setting cost allowances and allowed revenues is also likely to be more acceptable to the regulated entities and other stakeholders.

As with so many other aspects of regulation, there is no single preferred or best approach to cost assessment. As mentioned above, a combination of approaches can be used (ie they are not necessarily mutually exclusive), while **the key trade-off when determining the approach to be employed is between the efficiency incentives that might be provided to the regulated entity and the regulatory complexity involved**. Table 8, below, provides a summary review and sets out the relative merits of the main cost assessment methods used by the MOs.

Table 8 Summary evaluation of main MO cost assessment methods for opex

Assessment criteria	Bottom-up	Top-down	Yardstick	Totex
Efficiency incentives	Limited efficiency incentives, given focus on individual costs	Holistic approach should deliver stronger efficiency incentives	Strong efficiency incentives given revenue-cost decoupling	In principle, most consistent with efficiency as it also removes incentive to favour one type of expenditure to increase profits
Regulatory cost / complexity	Least costly approach as only firm-specific costs are assessed (albeit generally requires detailed examination of individual cost items/categories)	Requires access to a dataset of (partial) efficiency or productivity measures of comparator companies	Extensive and complex data and modelling requirements	Extensive and complex data and modelling requirements plus major change to regulatory regime and approach

Source: ECA

The table above does not include the '**historical outturn opex' approach**, which is **used in Czechia and Turkey** for both transmission and distribution. This approach, which entails reimbursing the TSOs' or DSOs' existing costs in a base year and then (usually) adjusting allowances in succeeding periods using an efficiency factor (based on an estimate of the rate of productivity change), has several important advantages including its relative simplicity and the strong incentives it provides for cost reduction over time (dynamic efficiency). We therefore discuss how this method could be applied by regulators in Box 3, below.

Box 3 The historical outturn opex approach

This approach to assessing controllable opex commences by (usually) taking the most recently available opex information (the 'base' opex), and rolling this forward taking into account:

- the scope for efficiency improvements
- increased costs driven by output growth
- changes in real prices, and
- any discontinuous or step changes in costs that are not otherwise captured.

Formulaically, this is represented as follows (which can be used for aggregate opex or by specific opex cost categories):

$$OPEX_t = OPEX_{base} \times (1 - X_t) \times (1 + G_t) \times (1 + RPA_t) + S_t$$

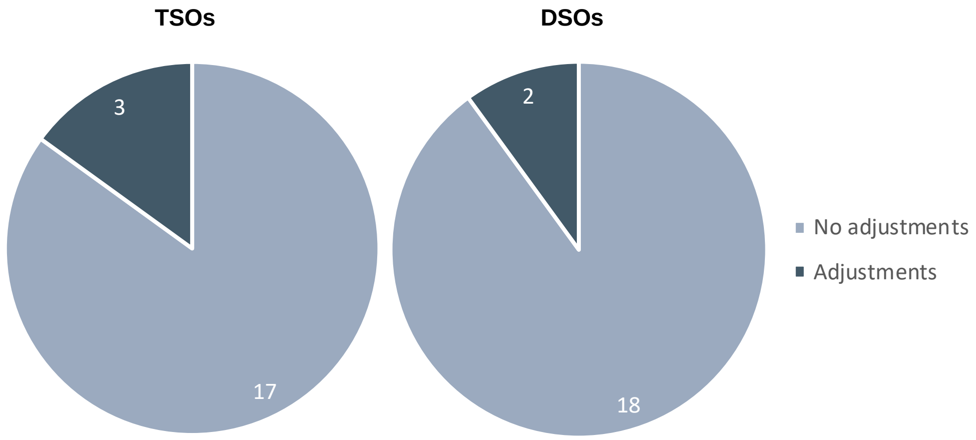
where:

$OPEX_t$	is the determined level of opex in year *t* of the forthcoming regulatory period
$OPEX_{base}$	is the level of opex in the base year
X_t	is the efficiency factor in year *t*
G_t	is the growth variable in year *t*
RPA_t	is the real price adjustment in year *t*
S_t	are step changes, ie determined extraordinary changes in expenditure in year *t*.

Employing the above formula and assessment approach effectively rolls base opex forward by the product of the annual rates of change in productivity, output growth and real prices in the forecast regulatory control period. The addition/subtraction of extraordinary changes accounts for any other efficient costs not captured in base opex or the rate of change. We note the following in relation to each element of the equation:

- **Base opex** – this is generally equal to the outturn expenditure in the last (available) year of the previous regulatory period, assessed for its reasonableness. However, adjustments to outturn expenditure might be needed when determining base opex in order to account for any material historical inefficiencies, or to exclude the costs associated with one-off events unique to the previous regulatory period. Regulators may also wish to substitute the last year of the previous period with another from that period (or an average across years), which is deemed to be more representative of efficient ongoing expenditure.
- **Efficiency factor** – this is intended to account for savings that the regulated network companies can reasonably be expected to be able to achieve in the future owing to productivity increases over time.
- **Growth variable** - the growth factor allows for the expected increase in costs of transmission and distribution network services as a result of increased demand and customer numbers, which would drive increases in opex over time even if the regulated TSOs and DSOs were operating on the efficiency frontier in all years.

Figure 13 Methods for addressing deviation from allowed opex



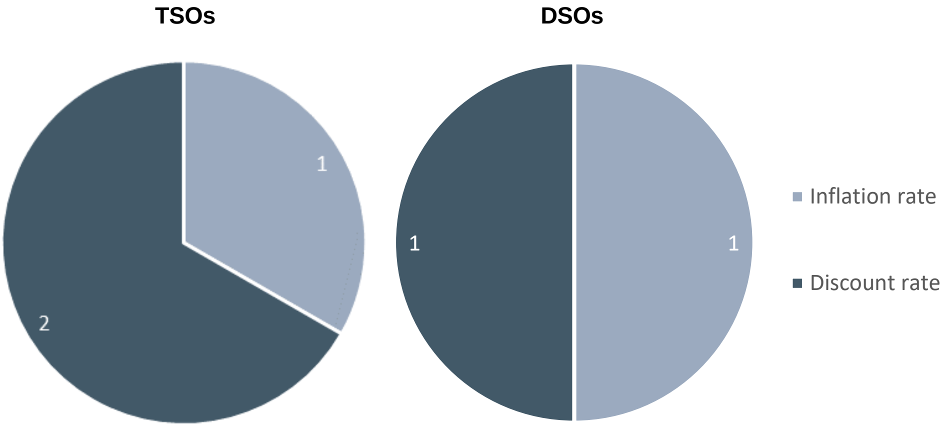
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Adjustment in next period for allowed opex deviation?*	✓	x	x	x	x	x	x	x	x	x	x	x	x	x	✓	x	x	x	x	✓
Share savings only																				✓
Share savings and overruns symmetrically	✓														✓					
DSO																				
Adjustment in next period for allowed opex deviation?*	✓	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	✓
Share savings only																				✓
Share savings and overruns symmetrically	✓																			

Source: Survey questions 3.9 and 3.10. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. *For some jurisdictions, such as those with a cost-plus regime, the question is irrelevant.

Deviations between allowed and actual opex in the current year are typically corrected for in future regulatory periods or in future years of the current regulatory period. However, $100 today differs from $100 in the future because of inflation and time-inconsistency of preferences (ie discounting). For this reason, **the value of the deviation from allowed opex today should in principle be adequately compensated for in future by considering inflation and discounting**.

In the ERRA sample, only Albania incorporates inflation considerations in its adjustments, and Kosovo and Peru only incorporate a discount rate (see Figure 14). Kosovo uses a short-term borrowing rate as the discounting rate, and Peru uses a rate set in law. Importantly, none of the regulators employ the cost of capital for making these adjustments.

Figure 14 Methods for compensating time value of allowed opex deviation



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Adjustment in next period for allowed opex deviation?*	✓	x	x	x	x	x	x	x	x	x	x	x	x	x	✓	x	x	x	x	✓
Inflation rate	✓																			
Discount rate															✓					✓
DSO																				
Adjustment in next period for allowed opex deviation?*	✓	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	x	✓
Inflation rate	✓																			
Discount rate																				✓

Source: Survey question 3.12. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. *For some jurisdictions, such as those with a cost-plus regime, the question is irrelevant.

4.1.4 Observations on the treatment of realised opex

As demonstrated above, for those MOs employing revenue or price caps, they almost exclusively (Albania, Kosovo and Peru are the exceptions) make no subsequent adjustments if realised opex is different to actual opex. That is, the process usually runs as follows:

- Regulators set allowed revenues using forecast opex and make no adjustments for the difference between forecast and actual expenditure.

- When allowed revenues are set for the next regulatory period, the starting point presumably reflects historical opex (and is therefore usually lower if savings were made in the last regulatory period) which would benefit network users in future (the 'ratchet effect') – note that if the 'historical outturn opex' approach discussed in Box 3 above is used, this must necessarily be the case.

The key weakness of the above approach to incentivising efficient expenditure is that it discourages savings late in the regulatory period, because the TSOs/DSOs will 'keep the benefit' for a shorter period; this disincentive is indeed even stronger in the case of the 'historical outturn opex' approach because expenditure in the latter years of the regulatory period sets the base opex for the forthcoming regulatory period. Network service providers therefore have an incentive to defer efficiency savings until the beginning of the next regulatory period and retain the benefit for longer. This means that efficiency incentives are not constant (and diminish) over time. Ideally, however, **efficiency incentives should be constant, that is, they should apply equal incentive strength to spending through time**. Some regulatory tools for ensuring constant incentives are described briefly in Box 4.

Box 4 Ensuring constant incentives for opex savings

One approach to ensuring constant incentives is to have an '**efficiency benefit sharing mechanism**', in much the same way as do Albania / Kosovo / Peru. While these adjustments are partly about ensuring that network users share the benefit of cost reductions (or shoulder some of the burden of cost increases), they are also mechanisms for ensuring constant incentives. A sharing mechanism generally operates as follows (although there are several variants to this):

- At the regulatory review, the over/under spend on opex is calculated for the recently completed regulatory period.
- The value of the cumulative over/under spend is calculated.
- A certain sharing ratio is applied to this amount.
    - The ratio applied to under/ over-spending can be asymmetric, to further protect users from the risk of the utility over-spending (Kosovo is a special case of this, where the sharing ratio for overspends is 0% ie only savings are shared).
- The above calculations then result in an adjustment to allowed revenues for the forthcoming regulatory period.

An equivalent or similar outcome is sometimes achieved through '**rolling incentive mechanisms**', which allow the regulated entity to retain the benefits of an efficiency improvement for a period of time (say, five years), after which the improvement is incorporated into the revenue requirement calculations. For example, if an efficiency gain is made in year three of a five-year regulatory period, the revenue requirement would not adjust to incorporate this until year three of the next control period. The basic rationale underlying this approach is that an entity can retain incremental efficiency gains for a period equivalent to the full duration of a regulatory period, irrespective of when in the period the gains are made (thereby directly addressing the time inconsistency problem).

4.1.5 Controllable versus uncontrollable opex

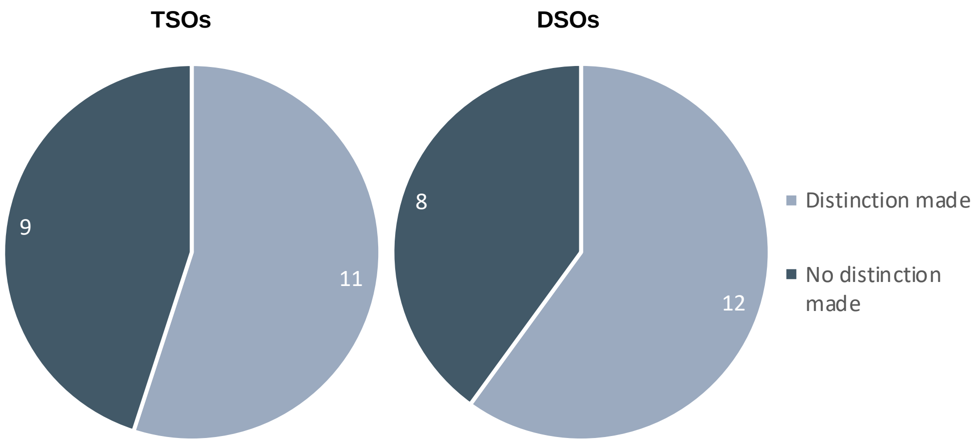
A fundamental objective of incentive-based regulation is to create incentives for cost minimisation and to allow the businesses to bear the consequences of poor management of the costs they control (and *vice versa*). This entails **placing risk with network businesses where they are able to manage the risk**. Where network businesses are unable to manage risks, there is a case for passing this exposure on to electricity consumers; while the latter are also unable to manage the relevant risk or cost, at least the risk is diversified by spreading it out across a wider group. This then allows network businesses, other things equal, to achieve more stable returns and access lower borrowing costs.

Accordingly, regulators often allow some uncontrollable opex to be passed through, at least partially, to end-users. **The general principle employed for treating elements of opex as pass-through is if they can be shown to be substantially outside the utility's influence and significant enough to have a material distorting impact on its finances**.

In the ERRA sample, **uncontrollable and controllable opex are distinguished at 11 TSOs and 12 DSOs**. Taxes, fees, and levies are the most common type of opex to categorise as uncontrollable (at ten TSOs and 11 DSOs). Other types of opex classified as uncontrollable include: salaries and wages; system losses; ancillary services; costs generated by force majeure; fuel costs; and connection charges (see Figure 15).

Most countries that distinguish between controllable and uncontrollable opex fully pass through the uncontrollable opex to network users. The only exception is Hungary, which partially passes through this uncontrollable opex to network users for both the TSO and DSO. Lithuania treats some TSO and DSO costs as pass-through only in exceptional cases, such as when there is a legislative amendment.

Figure 15 Opex categorised as uncontrollable



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Distinction of controllable & uncontrollable	x	✓	✓	x	x	✓	✓	✓	x	x	✓	✓	x	✓	x	✓	x	x	✓	✓
Taxes & fees		✓	✓			✓	✓	✓			✓	✓		✓		✓				✓
Salaries																✓				
System loss		✓																	✓	
Ancillary services												✓							✓	✓
Force majeure											✓			✓						
Fuel costs			✓																	
Connection charges														✓						

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
DSO																				
Distinction of controllable & uncontrollable	x	✓	✓	x	x	✓	✓	✓	x	x	✓	✓	x	✓	x	✓	✓	x	✓	✓
Taxes & fees		✓	✓			✓	✓	✓			✓	✓		✓		✓	?		✓	✓
Salaries																✓	?			
System loss		✓															?			
Ancillary services												✓					?			
Force majeure											✓			✓			?			
Upstream network costs		✓															?		✓	
Connection charges														✓			?			

Source: Survey question 3.3. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): Poland did not inform us which DSO opex items are classed as uncontrollable.

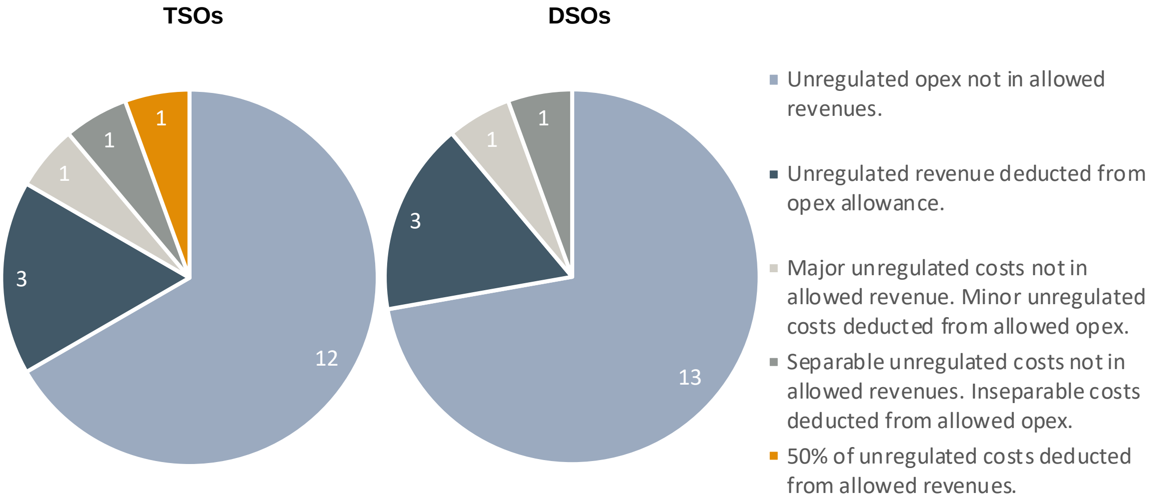
4.1.6 Regulated versus unregulated opex

Regulators often distinguish between opex incurred in regulated network services and opex from unregulated activities. This is done to ensure that **the regulated entity only recovers the cost of regulated services (ie those associated with network system operation)** and/or does not use regulated revenues to cross-subsidise other competitive activities.

For this purpose, the costs associated with unregulated activities are excluded from allowed revenues entirely if they are separately accounted for; otherwise, revenues generated from unregulated activities are deducted from the regulated businesses' opex allowance or allowed revenues. The latter is usually employed where there is no robust mechanism for allocating costs between the regulated and unregulated activities, and/or if there would not be significant distortionary impacts regarding both the electricity network tariffs and the markets for the unregulated services (assuming competition can be developed in those segments), or, finally, if the costs/revenues from the unregulated activities are immaterial.

In the ERRA sample, 19 TSOs and DSOs are required to distinguish between regulated and unregulated activities (see Figure 16). Of these, **most regimes exclude unregulated opex altogether from allowed revenues** (12 TSOs and 13 DSOs). Three TSOs and DSOs must deduct unregulated revenues from their opex allowance. Czechia's TSO and DSO exclude costs from 'major' unregulated activities from the opex calculation but only deduct revenue from 'minor' unregulated activities. Georgia's TSO and DSO exclude opex from unregulated activities from allowed revenues only if they can be separated from regulated opex, otherwise revenues from unregulated activities are deducted from allowed revenues. Oman's TSO deducts 50% of unregulated opex from allowed revenues; its DSO excludes unregulated opex completely from the allowed revenues.

Figure 16 Approaches for dealing with unregulated opex



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
Distinction of regulated & unregulated	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓
Unregulated opex not in allowed revenues	✓	✓	✓	✓		✓			✓	?	✓	✓	✓			✓	✓	✓		
Unregulated revenues deducted from opex allowance								✓		?					✓					✓
Major unregulated costs not in allowed revenue. Minor unregulated revenues deducted from opex allowance					✓					?										
Separable unregulated opex not in allowed revenues. Revenue from inseparable deducted from opex allowance.							✓			?										
50% of unregulated opex deducted from										?				✓						

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
allowed revenues																				
DSO																				
Distinction of regulated & unregulated	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Unregulated opex not in allowed revenues	✓	✓	✓	✓		✓			✓	?	✓	✓	✓	✓		✓	✓	✓		
Unregulated revenues deducted from opex allowance								✓		?									✓	✓
Major unregulated costs not in allowed revenue. Minor unregulated revenues deducted from opex allowance					✓					?										
Separable unregulated opex not in allowed revenues. Revenue from inseparable deducted from opex allowance							✓			?										

Source: Survey questions 3.5 and 3.6. Red marks indicate a divergence between the TSO and DSO method. [†]See Footnote 2. Unclear data (?): We understand that Latvia distinguishes regulated and unregulated opex, but we were unable to find out how they deal with revenues from unregulated opex.

4.1.7 Opex efficiency improvements

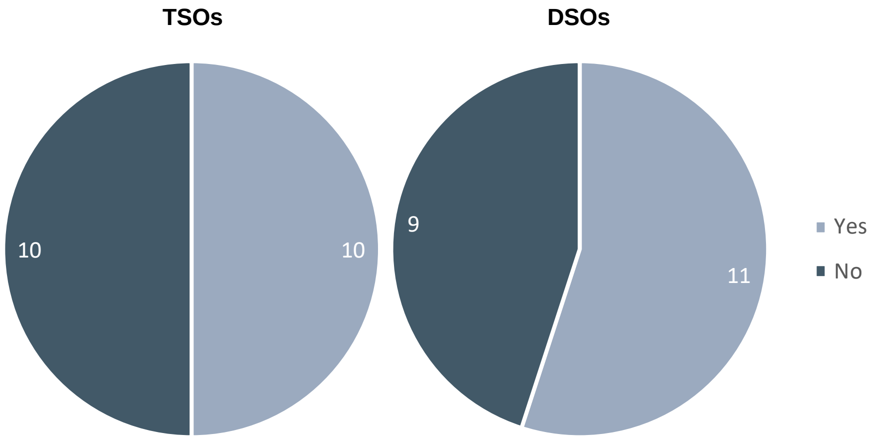
In a regime where the allowed opex is determined *ex-ante*, for example in the building blocks of a revenue cap, the regulator may assume an opex efficiency improvement in each year. (This efficiency factor contrasts with the general *X-efficiency* factor at the level of the overall price or revenue in the form of CPI-X.)

Assuming an efficiency factor for opex is more commonplace than for capex. The opex efficiency factor is also often only applied to sub-components of opex; **it is mostly applied at the distribution level**, because of the greater number of comparator firms.

The determination of an opex efficiency factor is often selected based on 'expert opinion'. The percentage selected in such a process is often the culmination of observing past opex trends of the relevant entity and the opex productivity factors adopted by other regulators. However, the regulator may also adopt a benchmarking approach more formally.

In the ERRA sample, an opex efficiency factor is applied to ten TSOs and 11 DSOs (see Figure 17). Pakistan and Turkey use an opex efficiency factor for DSOs but not for TSOs, whereas Nigeria uses one for the TSO but not for the DSO. The efficiency factors, reported in the table below, range from 1%-4%. Expert opinion is the most common method for calculating the factor (five TSOs and four DSOs), meaning entities adopt flexibility in their methodological approach. Also adopted are external benchmarking (three TSOs and four DSOs), and internal benchmarking (used only by Turkey's DSO).

Figure 17 Opex efficiency factors



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Opex efficiency factor?	x	✓	✓	x	✓	x	✓	✓	✓	x	x	x	✓	✓	x	x	✓	x	x	✓
External benchmarking		✓	?				✓						?							✓
Expert opinion			?		✓			✓	✓				?	✓			✓			
Factor (%)		?	?		1%		1.5%	1.5%	1%				4%	1%			1.5%			1.5%
DSO																				
Opex efficiency factor?	x	✓	✓	x	✓	x	✓	✓	✓	x	x	x	x	✓	x	✓	✓	x	✓	✓
External benchmarking		✓	?				✓									✓	?			✓
Internal benchmarking			?														?		✓	
Expert opinion			?		✓			✓	✓					✓			?			
Factor (%)		?	?		1%		1.5%	1.5%	1%					1%		<3%*	1.5%			1.5%

Source: Survey questions 3.7 and 3.8. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. *The efficiency factor for Pakistan is 30% of the CPI inflation rate. However, the factor cannot exceed 3%. Unclear data (?): For Azerbaijan and for Poland's DSO, we were unable to find out how they determine their opex efficiency factors. For Azerbaijan, we were unable to find out their most recently determined factors. Austria's regulator did not wish to make their value publicly available.

4.1.8 Observations on the incorporation of efficiency improvements

There is currently limited use made of efficiency factors either at the level of the tariff or revenue control (see Section 3.7) **or in setting cost allowances** (as shown above). While determining efficient costs and/or defining the magnitude of any efficiency gaps is not straightforward, this is at the heart of what regulators are tasked with and therefore we would suggest this needs to feature more prominently. Also, there are grounds for believing that inefficiencies are likely to be material in the TSO/DSO sectors of the MOs (and thereby justifying greater scrutiny) for several reasons, including:

- the monopoly status of the TSOs and DSOs means that they are shielded from competition, and the absence of competition is generally associated with reduced efficiency;
- many of the MO regulated businesses are state-owned and cannot be acquired by or merged with other companies, so there is the absence of the threat of hostile takeovers that could act as a discipline for operating efficiently; and
- evidence from cost benchmarking studies of electricity transmission and distribution suggests that there are very large divergences between the most and least efficient businesses.

Box 5 describes the factors that would need to be considered in setting efficiency factors.

Box 5 Incorporation of an efficiency factor in setting opex allowances

The efficiency factor (sometimes termed the 'X-factor') is intended to account for savings that the regulated TSOs and DSOs can reasonably be expected to be able to achieve in the future owing to productivity increases over time. In assessing forecast productivity, MO regulators would likely need to consider (among other things):

- The business' **historical productivity performance** using disaggregated cost data from the regulated entities.
- Forecast **output growth** and economies of scale.
- Expected future **changes in technology** and the forecasted **specific business conditions** of the TSOs and DSOs.
- Total and/or partial **productivity measures** of comparator companies or for the broader industrial sector in the relevant MO countries, if there is an absence of electricity network comparators.
- The dynamic **efficiency factors set by other regulators** and available evidence from **relevant literature**.

While the available evidence is limited, in our experience we have found that **electricity transmission** businesses should be able to achieve growth in total factor productivity (TFP), if already operating at or close to the frontier, of **around 2% annually**. **The corresponding X-factor would be somewhat lower**, allowing for that part of TFP growth included in economy-wide price indices. Adding in an allowance for catch-up growth would increase this value accordingly. However, this is for TFP growth; growth in operating cost and labour cost productivity is generally higher. However, many regulators generally tend to set efficiency factors for operating costs in line with expected TFP growth - possibly to account for the inherent uncertainty in such estimations and to err on the side of caution so as not to risk placing TSOs into financial difficulties.

In the case of distribution, there is more available evidence, but it is also more varied, although **a range of 1.5%-2% annual real efficiency gains is common**. In some countries, particularly where structural change has occurred, with unbundling, privatisation and/or the introduction of incentive regulation, more rapid productivity growth has been assumed; in others, with more established regimes and industries in a relatively 'steady state', lower efficiency gains have been assumed.

As can be seen, the above is broadly **in line with the magnitude of efficiency gains being assumed by those MO regulators that do employ efficiency factors**.

4.1.9 Tools for benchmarking opex

Regulators have a selection of statistical benchmarking tools at their disposal for the yardstick or top-down approach. These tools establish a reasonable efficient opex for the utility by observing other utilities in the sector, the utility's own performance over time, and/or a hypothetical 'ideal' utility. The tools, outlined in Table 9, can be categorised as parametric or non-parametric.

If a parametric approach is used, the regulator specifies a parametric production or cost function. That is, they express output y_i as a function of inputs X_i for firm i, where the function is clearly defined with parameters (independent of i) to be estimated to represent an average production function or production possibility frontier (PPF). The most common parametric approaches are *ordinary least squares* (OLS), *corrected ordinary least squares* (COLS), and *stochastic frontier analysis* (SFA).

If a non-parametric approach is used, no assumption is made about the form of the production function or the distribution of the sample or population data. The most common non-parametric methods are *data envelopment analysis* (DEA), *total factor productivity* (TFP), and *partial productivity indices* (PPIs).

These tools can be used for benchmarking based on two concepts: *comparator networks* or *frontier shift*. The former concept uses data from a network of comparator countries to produce a static production function or PPF. The latter incorporates a further assumption that this PPF will expand outwards over time in line with technical development; the latter can alternatively be based solely on the utility's own past data, rather than on a reference network of data from other entities.

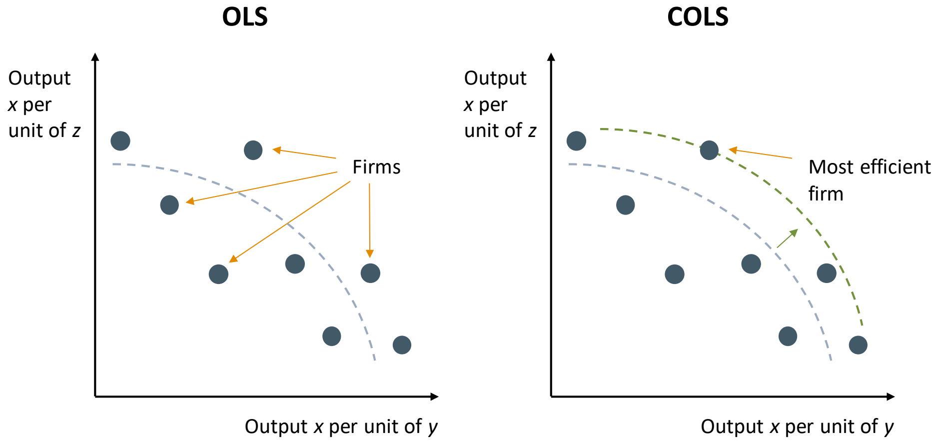
Table 9 Methods for statistical benchmarking

Method	Description
Statistical tools	
OLS	▪ Specifies a parametric production or cost function (ie expresses output y_i as a function of inputs X_i for firm i, where the function is clearly defined with parameters to be estimated). ▪ The parametric function, typically a Cobb-Douglas or translog function, contains a random noise component. For example, $y_i = ax_{i,1}^{b}x_{i,2}^{1-b}\exp(\varepsilon_i), \quad a \in \mathbb{R}_+, \quad b \in [0,1], \quad \varepsilon_i \sim N(0,1).$

Method	Description
	▪ The parameters in the (log-transformed) function are estimated using cross-sectional data or panel data from comparable utilities in the industry. This represents the average production function (see left-hand side of Figure 18).
COLS	▪ Extends the OLS approach by shifting the estimated fitted values to intersect with the data points for the most efficient company. This represents the production possibility frontier (see right-hand side of Figure 18).
SFA	▪ Similar to OLS/COLS, but the functional form indicates that efficiency improvements are partly random. For example, $y_i = \exp(-v_i) x_{i,1}^{b} x_{i,2}^{1-b} \exp(\varepsilon_i), \quad a \in \mathbb{R}_+, \quad b \in [0,1], \quad v_i, \varepsilon_i \sim N(0,1).$
DEA	▪ Instead of assuming a shape for the production possibility frontier and attempting to estimate it, the regulator observes the frontier formed by the most efficient comparable utilities (see Figure 19).
TFP	▪ Measures change in total output relative to the use of all inputs, for example: $lnTFP_{st} = \ln \frac{output\ Index_{st}}{input\ Index_{st}},$ from period s to period t. ▪ Commonly adopted is the Tornqvist index.
PPI	▪ Measures total output relative to the use of individual inputs, for example the average product of labour and capital: $AP_t^L = \frac{L_t}{y_t}, \quad AP_t^K = \frac{K_t}{y_t}$ for period t for labour input L, capital input K, and output y.
Statistical concepts	
Reference network	▪ Measures a static PPF based on the data of a network of comparator countries.
Frontier shift	▪ Evaluate efficient current costs (either based on a reference network or the firm's own past costs) to estimate a PPF. ▪ Assume the PPF will expand outwards over time in line with technical development.

Source: [1] ECA; [2] Khetrapal and Thakur (2014), *A Review of Benchmarking Approaches for Productivity and Efficiency Measurement in Electricity Distribution Sector* [3] IBNET, *Statistical Techniques*[14]

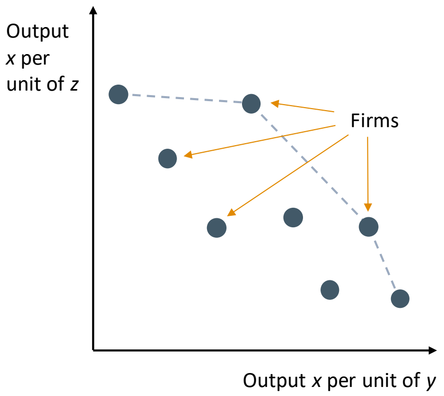
Figure 18 OLS and COLS in statistical benchmarking



Source: ECA

[14] https://www.ib-net.org/benchmarking-methodologies/performance-benchmarking/statistical-techniques/

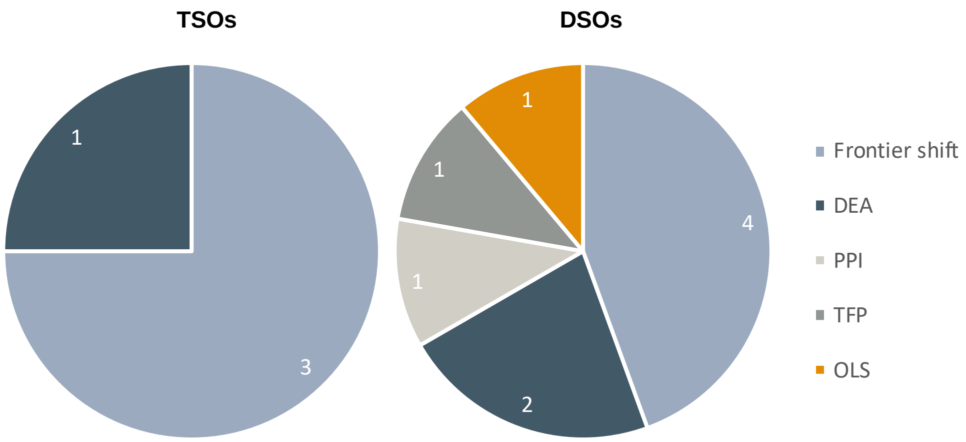
Figure 19 Data envelopment analysis in statistical benchmarking



Source: ECA

In the ERRA sample, the most common approach is to evaluate actual costs and then assume a frontier shift (three TSOs and four DSOs) (see Figure 20). Two DSOs and one TSO use data envelopment analysis, one DSO uses a partial productivity index, one DSO uses total factor productivity, and one DSO uses ordinary least squares.[15]

Figure 20 Opex benchmarking methods



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Frontier shift													✓	✓						✓
DEA		✓																		
DSO																				
Frontier shift						✓							✓	✓						✓
DEA		✓																	✓	
PPI								✓												
TFP																✓				
OLS		✓																		

Source: Survey question 3.2. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

[15] In fact, Austria uses a variation of OLS known as *modified* ordinary least squares.

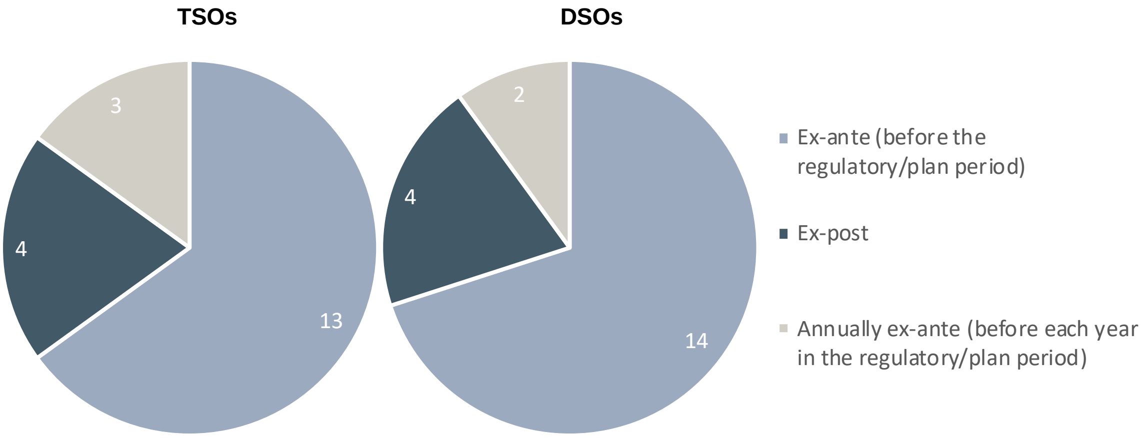
4.2 Capex and RAB

4.2.1 Determination of allowed capex

The value of capital expenditure (capex) is tied to the cost of each investment project or programme. **The regulator may approve this capex either before the utility undertakes the project (*ex-ante*) or after the project has begun (*ex-post*).**

In the ERRA sample, capex is approved before the start of the regulatory or investment-plan period for 13 TSOs and 14 DSOs (see Figure 21). At three TSOs and two DSOs, capex is approved at the beginning of each year within the regulatory or investment-plan period. This means **most regulators approve capex *ex-ante*** (16 TSOs and DSOs). In the case of four TSOs and DSOs, capex is approved *ex-post*.

Figure 21 *Ex-ante* versus *ex-post* approval of capex



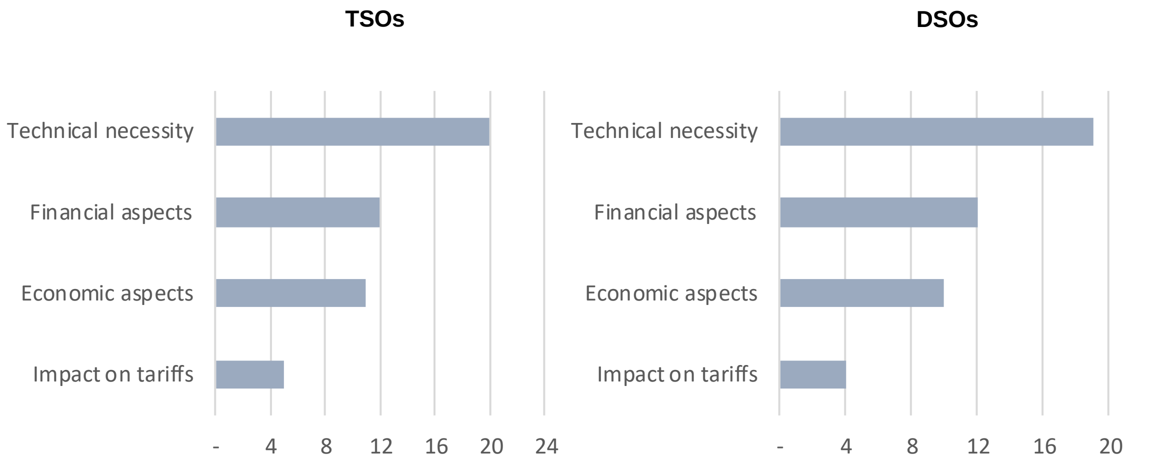
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
Ex-ante (before the regulatory / plan period)	✓		✓	✓		✓	✓					✓	✓	✓	✓	✓	✓		✓	✓
Ex-post		✓			✓			✓										✓		
Annually *ex-ante*									✓	✓	✓									
DSO																				
Ex-ante (before the regulatory / plan period)	✓		✓	✓		✓	✓			✓		✓	✓	✓	✓	✓	✓		✓	✓
Ex-post		✓			✓			✓										✓		
Annually *ex-ante*									✓		✓									

Source: Survey question 4.2. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

The regulator has different means for deciding whether to approve capex. These could include technical necessity of the project (security of supply, accommodating load, etc), financial aspects of the project (net present value, internal rate of return, benefit-cost ratio, payback period, etc), the economic aspects of the project (broader socio-economic impacts), or whether the project has a net impact on the tariff. Regulators sometimes base their decision on a mix of these factors.

In the ERRA sample, **technical necessity is the most common means for approving capex** (20 TSOs and 19 DSOS), followed by financial aspects of the capex (12/12), economic aspects (11/ten), and the impact of the capex on tariffs (five/four) (see Figure 22). In Nigeria, the impact on tariffs is considered when approving TSO capex, but not DSO capex. In Hungary, the impact on tariffs will be considered for the TSO and DSO from 2021.

Figure 22 Means for approving capex



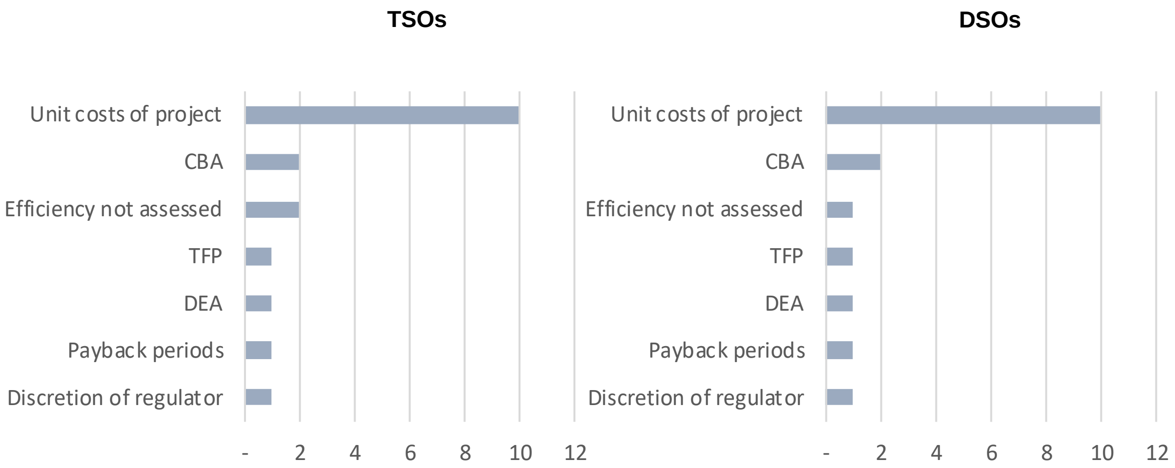
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Technical necessity	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Financial aspects	✓	✓	✓	✓			✓					✓	✓	✓		✓	✓		✓	✓
Economic aspects	✓	✓		✓		✓	✓		✓	✓	✓	✓	✓			✓				
Impact on tariffs							✓						✓			✓			✓	✓
DSO																				
Technical necessity	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	?	✓	✓	✓	✓	✓
Financial aspects	✓	✓	✓	✓			✓					✓	✓	✓	?	✓	✓		✓	✓
Economic aspects	✓	✓				✓	✓		✓	✓	✓	✓	✓		?	✓				
Impact on tariffs							✓								?	✓			✓	✓

Source: Survey question 4.3. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): We were unable to determine Peru's means for approving DSO capex.

For regulators adopting a process of *ex-ante* approval of capex, they may stipulate that the utility demonstrate efficiency of the project before it can go ahead. They have various means for testing capex efficiency *ex-ante*, and multiple approaches can be adopted.

In the ERRA sample, **the most common approach for assessing capex efficiency when approving capex *ex-ante* is to observe the unit cost of the project** (ten TSOs and DSOs) (see Figure 23). Cost-benefit analysis is the second-most common means, but this is only practised in Pakistan and Kosovo. Turkey is the only country to use a different approach for DSO and TSO capex efficiency assessment; the unit cost is observed for the former, while efficiency is not assessed for the latter.

Figure 23 Methods for assessing capex efficiency *ex-ante*



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Unit cost of project	✓		✓			✓	✓				✓	✓	✓	✓	✓		?			✓
CBA																✓	?			✓
Efficiency not assessed									✓								?		✓	
TFP				✓													?			
Payback periods																✓	?			
Discretion of regulator										✓							?			
DEA				✓													?			
DSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Unit cost of project	✓		✓			✓	✓				✓	✓	✓	✓	?		?		✓	✓
CBA															?	✓	?			✓

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Efficiency not assessed									✓						?		?			
TFP				✓											?		?			
Payback periods															?	✓	?			
Discretion of regulator										✓					?		?			
DEA				✓											?		?			

Source: Survey question 4.5. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): We were unable to find out how Poland assesses capex efficiency *ex-ante*. For the DSO, Peru explains that the rules have not yet been approved by the Ministry of Energy and Mines, so it is currently unclear how they will measure the efficiency of DSO capex *ex-ante*.

4.2.2 Observations on capex assessment

From the above information it may be concluded that in most (although not all) cases among the MOs, **capex requirements are largely determined based on technical necessity, while the reasonableness of costs is assessed by looking at unit costs**. The application of economic assessments for justifying the need for expenditure is less common, as is the use of a broader range of analytical methods for determining efficient capex costs.

Given that electricity networks are characterised by large fixed costs and therefore sizeable and lumpy investment which in turn drives a significant component of the network business' allowed revenues, we would suggest that **regulators ought to be subjecting *material* capex proposals to greater scrutiny, both to ensure that the proposed investments are needed (and those that best meet objectives compared to alternatives), and that they are delivered at the lowest possible cost**. In the two boxes below, we expand more on the use of cost-benefit analysis for determining investment need and some possible methods for assessing the reasonable costs of different capex categories, respectively.

Box 6 Economic assessment of capex proposals

Under this approach, the cost submissions for substantive investment projects or programmes of the electricity network businesses would necessarily be **underpinned by economic justification**. That is, the businesses would be required to demonstrate (quantitatively) that the forecast expenditure is expected to be **the lowest cost option in the long-run relative to other feasible options** in net present value terms. Note that this assessment would need to give **equal consideration to the interests of those who consume, produce and transport/distribute electricity**, with the aim of identifying both the most efficient network projects, and any more efficient non-network options, such as demand management, where they exist.

The fundamental requirement is that the chosen expenditure must be demonstrably superior to other options. To establish the economic case for the transmission or distribution investment, the TSO/DSO submissions would need to contain:

- relevant information about the background to the proposed expenditure (typically this is set out in asset management plans);
- the expected benefits;
- the options considered (with reasons for rejecting or proposing each option);

- the expected costs of the project; and
- the expected risks (including to the stability of the network).

Any such analysis would generally be **focused on expenditure decisions for groups of assets or individual projects that materially affect forecast expenditure**. This is because the economic analysis itself is a costly process. It should also be emphasised that such analysis is not an 'exact science' and will require assumptions, simplifications and decisions about whether to include or exclude entire classes of benefits. However, a major advantage of such an approach, which is usually conducted in an open consultative process with interested parties, is that it **provides a forum for parties with relevant information, such as suggested alternative solutions, to come forward and for assumptions and methodologies to be challenged**.

Box 7 Informational requirements of capex cost assessment methods

The assessment of capital expenditure usually requires consideration of the different categories (and drivers) of expenditure on a transmission and distribution network. This typically comprises the following:

- refurbishment or replacement of specific network segments;
- extension and reinforcement of the network;
- the provision of new customer connections and metering; and
- other capex, such as the installation of any new information systems.

The table below describes these expenditure categories and lists some of the assessment methods and the associated information that would need to be submitted to the regulator for undertaking more detailed reviews of such investment.

Capex type	Description	Assessment methods	Informational needs
All categories	See below	• Methodology and input analysis • Governance review • Economic analysis	• Modelling tools and assumptions used for forecasts • Key decisions contained in asset management plans • Demonstration that any material changes in expenditure relative to historical expenditure levels is efficient and prudent • Governance plans relating to capital expenditure and evidence where they have or have not been followed • Planning and strategy documentation for key capex categories and activities (including asset management plans)
Refurbishment and	Incurred to address the deterioration	• Analysis of information justifying the expenditure (eg condition and risk assessments, and safety,	• Quantum of assets added and disposed of in recent

replacement capex	of existing assets	reliability and performance information) • Comparison of forecast capex with historical expenditure • Detailed project and engineering reviews	years, and those forecast by key asset category • Age distribution of assets by key asset category • Expected costs associated with replacing assets in each category • Data justifying historical and forecast replacement activities
Capex for network extension (augmentation and reinforcement)	Required by a need to build or augment network assets to address changes in or to maintain and/or improve the quality, reliability and security of supply	• Examination of the capex governance framework (including investigation of how the augmentation expenditure relates to the system and network development plans) • Investigation of the methodology, assumptions, inputs and calculations for projecting demand • Examination of the relationship between the demand forecasts and the proposed projects and programmes • Detailed technical reviews of specific projects	• Demand forecasts (including global and spatial peak demand), the models underpinning the forecasts and key assumptions and inputs • Issues the augmentation might be addressing (eg capacity constraints, voltage constraints, load movement, security, quality of supply, etc) • Historical and forecast information on the various segments of the network related to demand, utilisation and augmentation cost • Historical and forecast costs associated with the unit cost of key augmentation inputs (eg transformers, switchgear, line works, etc)
New customer connection and metering capex (distribution only)	Customer-initiated connection works, usually to the distribution system	• Because these are customer-specific, they usually require reviewing the specific connection works with the assistance of technical consultants (if needed) to undertake a detailed project review • In some cases (eg standard residential connections) there is value in obtaining standardised information that would permit the use of trend analysis or other techniques to assess such expenditure	Volume and cost for standardised categories of work, such as: • Single and multi-phase connections • Transformers used in complex connections • Capacity added (km) and MVA added for customer connections • Underground and overhead connections
Other capex	Generally relate to activities that	• Some of this is recurrent expenditure, in which case it can be assessed more	Information on forecast volumes and costs for a number of standardised

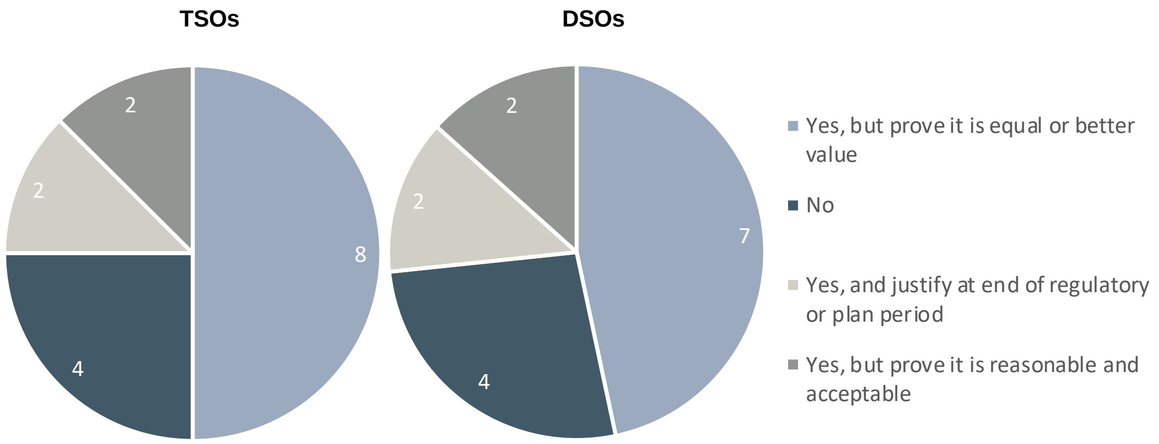
	are indirectly associated with the networks, eg IT, buildings, vehicles, etc	like opex using, for example, revealed costs in the past and techniques such as 'trend analysis' and predictive modelling	categories of works, split wherever possible into recurrent and non-recurrent expenditure, eg for: • IT and communications • Vehicles • Plant and equipment • Buildings and property

4.2.3 Allowed versus actual capex

In the case of *ex-ante* approval of capex, the approved capex plan applies over a fixed period, such as the regulatory period or a distinct investment-plan period. **At the time of implementing the project, the TSO or DSO may find it beneficial to diverge from the pre-approved plan**. Whether this is permitted differs across jurisdictions.

In the ERRA sample, eight TSOs and seven DSOs are permitted to deviate from *ex-ante* approved capex during the regulatory period or investment-plan period if they can prove that the alternative plan is equal or better value than the original plan (see Figure 24). For four TSOs and DSOs, no such deviation from the plans is permitted; for Moldova, this is because they approve capex every year, so a deviation would be inappropriate. In Albania and Georgia, deviation is permitted for both the TSO and DSO, if they can prove this is 'reasonable and acceptable'. In Oman and Pakistan, deviation is permitted for both the TSO and DSO, and they can justify at the end of the regulatory or plan period.

Figure 24 Whether deviation from *ex-ante* approved capex is allowed



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Yes, but prove it is equal or better value						✓			✓			✓	✓		✓		✓		✓	✓

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
No			✓	✓						✓	✓									
Yes, and justify at end of regulatory or plan period														✓		✓				
Yes, but prove it is reasonable and acceptable	✓						✓													
DSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Yes, but prove it is equal or better value						✓			✓			✓	✓		?		✓		✓	✓
No			✓	✓						✓	✓				?					
Yes, and justify at end of regulatory or plan period														✓	?	✓				
Yes, but prove it is reasonable and acceptable	✓						✓								?					

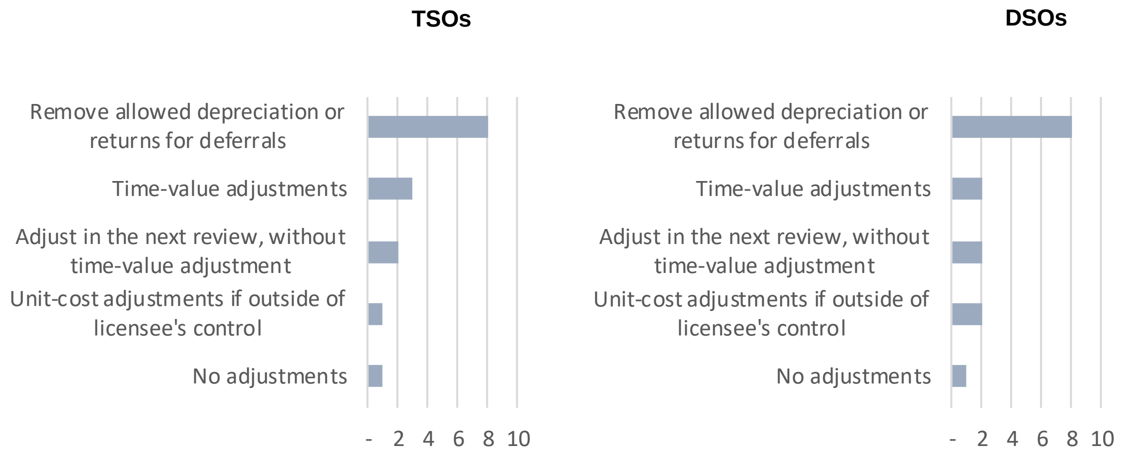
Source: Survey question 4.4. †See Footnote 2. Unclear data (?): For the DSO, Peru explains that the rules have not yet been approved by the Ministry of Energy and Mines, so it is currently unclear whether deviation from *ex-ante* approved capex will be permitted.

In forward-looking regimes, the *ex-ante* approved capex partially determines the level of allowed revenue in each year of the regulatory period. **If the utility deviates from its approved capex during the regulatory period, the regulator may have provisions in place for automatically adjusting the allowed revenue** in these circumstances before the next regulatory review takes place.

The adjustments required depend on the type of deviation between approved and actual capex. The deviation could result from *deferred* capex, ie capex that was planned in the current period but delayed, or due to over- or under-spending. In the case of capex deferral, the regulator could remove allowed depreciation or returns for these investments from the allowed revenues. Alternatively, the regulator could amend the present value of the investment by discounting more heavily, given that the commissioning year will be later. In the case of general over- or under-spending on non-deferred investments, the regulator could again amend the present value of the investment, but this time by adjusting the capex in each year.

In the ERRA sample, eight TSO and DSO regimes automatically remove depreciation and allowed return on deferred capex (see Figure 25). Three TSO and two DSO regimes adjust the time value of money. For two TSOs and DSOs, adjustments are made in the next review without compensating for the time value of money. Kosovo and Bulgaria make unit-cost adjustments for the DSO if the deviation was outside the licensee's control, and Bulgaria also for the TSO. Estonia makes no adjustments.

Figure 25 Adjustments if actual capex deviates from *ex-ante* approved



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Remove allowed depreciation or returns for deferrals	✓		?	✓					?	?	✓		✓	?		✓	✓		✓	✓
Time-value adjustments			?				✓		?	?				?	✓				✓	
Adjust in the next review, without time-value adjustment			?						?	?		✓		?			✓			
Unit-cost adjustments if outside of licensee's control			?	✓					?	?				?						
No adjustments			?			✓			?	?				?						
DSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Remove allowed depreciation or returns for deferrals	✓		?	✓					?	?	✓		✓	✓	?	✓			✓	✓
Time-value adjustments			?				✓		?	?					?				✓	

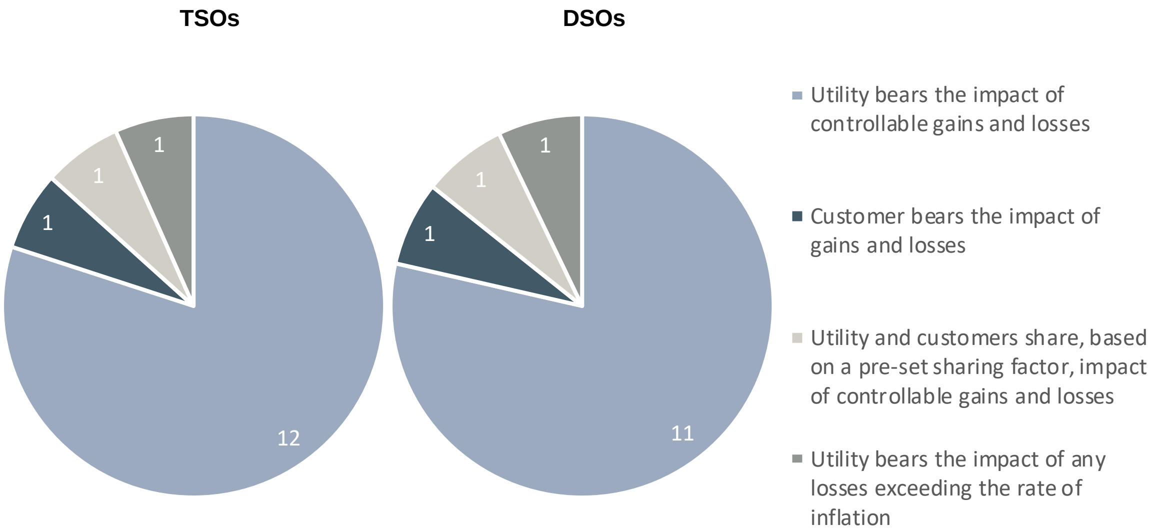
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Adjust in the next review, without time-value adjustment			?						?	?		✓			?		✓			
Unit-cost adjustments if outside of licensee's control			?	✓					?	?					?					✓
No adjustments			?			✓			?	?					?					

Source: Survey question 4.7. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): Azerbaijan explains they are in the first year of implementing their methodology, which has created limitations that mean they do not currently know the answer to this question. For Latvia and Lithuania, we were unable to find out what is their approach if TSO or DSO actual capex deviates from *ex-ante* approved capex. We were also unable to determine this approach for Oman's TSO. For the DSO, Peru explains that the rules have not yet been approved by the Ministry of Energy and Mines, so it is currently unclear whether deviation from *ex-ante* approved capex will be permitted.

Over- or under-spending on non-deferred capex could be shared between the utility and the consumer, as with opex, for example based on a pre-set sharing factor. This may be conditional on whether the reasons were outside the licensee's control.

In the ERRA sample, **most reported that the utility bears the full impact of any over- or under-spending on capex** (12 TSOs and 11 DSOs) (see Figure 26). In Albania, gains and losses are shared between the utility and customers based on a pre-set sharing factor, but only if the reason was within the utility's control. For the TSO and DSO of Georgia, the customer bears the full impact of gains and losses. In Moldova, TSO and DSO overspends exceeding the rate of inflation are covered by the utility.

Figure 26 Approaches for sharing capex efficiency gains and losses



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Utility bears impact			✓	✓		✓			✓	✓		✓	✓	✓	✓	?	✓		✓	✓
Customer bears impact							✓									?				
Utility and customers share impact	✓															?				
Utility bears losses above inflation											✓					?				
DSO																				
Capex determined *ex-ante*?	✓	x	✓	✓	x	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓
Utility bears impact			✓	✓		✓			✓	✓		✓	✓	?	?	✓	✓		✓	✓
Customer bears impact							✓							?	?					
Utility and customers share impact	✓													?	?					
Utility bears losses above inflation											✓			?	?					

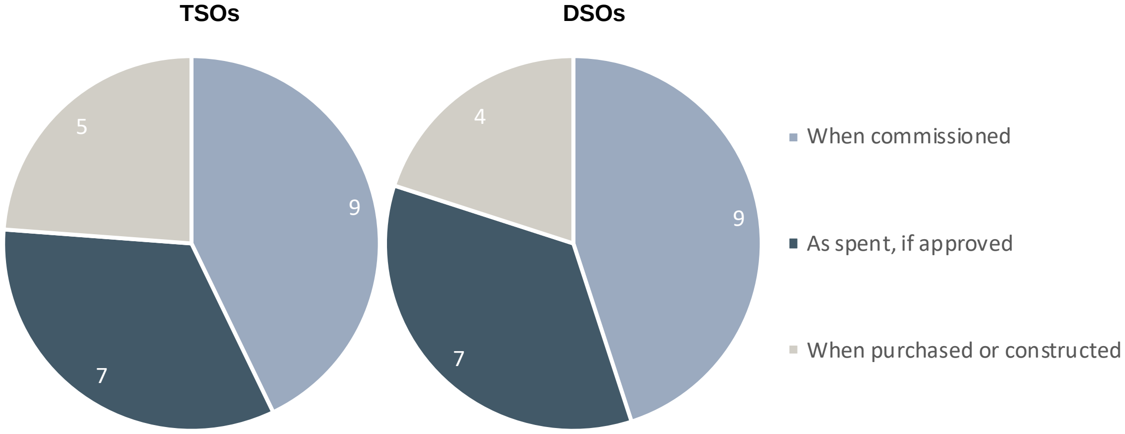
Source: Survey question 4.8. †See Footnote 2. Unclear data (?): For Pakistan, we were unable to determine what is their approach for sharing TSO capex efficiency gains and losses between the utility and customers. Similarly, we were unable to determine the approach applied to Oman's DSO. For the DSO, Peru explains that the rules have not yet been approved by the Ministry of Energy and Mines, so their approach for sharing capex gains and losses is currently unclear.

4.2.4 Capex in the RAB

Once capex enters the regulatory asset base (RAB), the utility is permitted to raise revenues to cover depreciation and returns on that capital. **There are various points that capex could enter the RAB: once the money is spent (provided it is approved); once the asset is constructed; or once the asset is commissioned and becomes 'used and useful'**. The key advantage of adding capital expenditure when it is incurred is that it is easier to administer because there are no complexities related to capex being incurred in one regulatory period but not commissioned until the next. The key disadvantage is that users may pay for capex that is not yet operational and will not be for some years ahead. On the other hand, including investments only once they are fully constructed or commissioned can create financing difficulties for the regulated entity. There is no consensus among regulators on the 'best' approach.

In the ERRA sample, for nine TSOs and DSOs, capex enters the RAB when commissioned (see Figure 27). Seven TSOs and DSOs have capex entering the RAB as spent or incurred, providing it has been approved. At five TSOs and four DSOs, capex enters the RAB when assets are purchased or constructed. For Latvia, where this is normally the case, projects of common interest (PCI)[16] are treated differently; for these projects, capex enters the RAB as it is incurred.

Figure 27 When capex enters the RAB



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
When commissioned			✓		✓		✓	✓			✓					✓		✓	✓	✓
As spent, if approved		✓		✓		✓			✓				✓	✓		✓				
When purchased or constructed	✓									✓		✓			✓		✓			
DSO																				
When commissioned			✓		✓		✓	✓			✓				?	✓		✓	✓	✓
As spent, if approved		✓		✓		✓			✓				✓	✓	?	✓				
When purchased or constructed	✓									✓		✓			?		✓			

Source: Survey question 4.10. †See Footnote 2. Unclear data (?): For Peru, we were unable to find out when the DSO's capex enters the RAB.

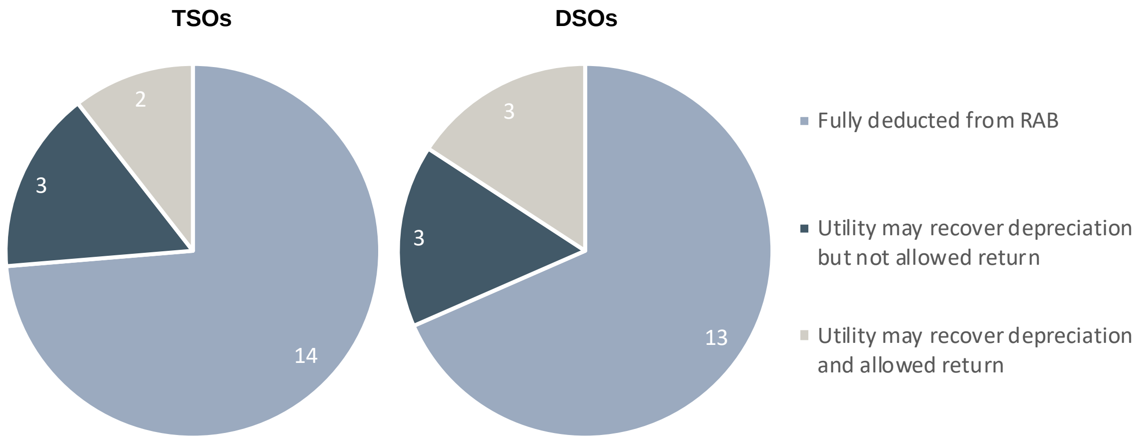
One important consideration is **how to deal with contributions and grants from third parties for investment projects**. Because the utility has not incurred that capex, such capex is generally excluded from the RAB for the purposes of earning a return. However, a case could be made that the utility should be permitted to recover depreciation in order to be able to fund the replacement of the asset in future.

In the ERRA sample, t**he majority fully deduct capital contributions from the RAB** (14 TSOs and 13 DSOs). Three TSO and DSO regulatory regimes allow the utility only to recover depreciation expenses on the capital contributions, while two TSOs and three DSOs are allowed to recover both depreciation expenses and a return. In Peru, there is a distinct approach for the TSO and DSO; contributions to the TSO are deducted from the

[16] PCIs are key cross-border infrastructure projects that link the energy systems of EU countries.

RAB, while the DSO may recover both deprecation and a return on contributions to the DSO.

Figure 28 Capital contributions and grants in the RAB



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Deducted from RAB	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓			✓	✓	✓	?			✓
Recover depreciation but not return					✓							✓	✓				?			
Recover depreciation and return																	?	✓	✓	
DSO																				
Deducted from RAB	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓			✓		✓	?			✓
Recover depreciation but not return					✓							✓	✓				?			
Recover depreciation and return															✓		?	✓	✓	

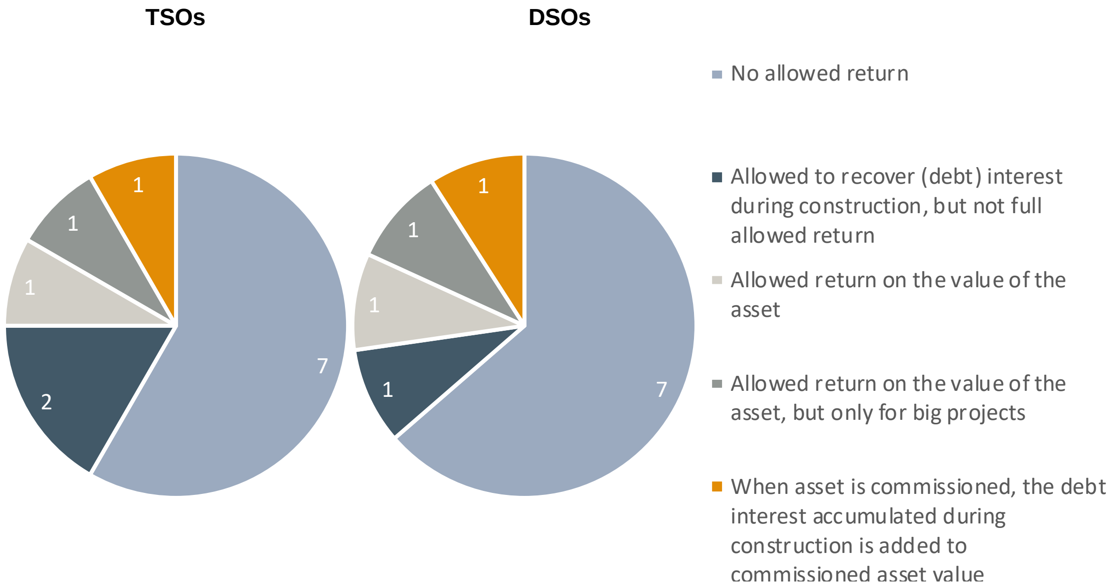
Source: Survey question 4.14. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): For Poland, we were unable to find out whether or how capital contributions and grants enter the RAB.

In the case that capex enters the RAB once the money is spent, the utility is permitted to begin raising revenue for those investments immediately. If not, the utility may have to wait a substantial period to raise revenues to cover expensive capital investments. A common compromise to address this issue is to **allow construction work in progress (CWIP) to enter the RAB at a grossed-up value that includes financing costs during construction**.

In the ERRA sample, the most common approach is in fact to not allow any return on CWIP (seven TSOs and DSOs) (see Figure 29). Two TSOs and one DSO are permitted to recover debt interest during construction, but not the full allowed return. North Macedonia allows the TSO and DSO to recover the full allowed return on the value of the

CWIP. In Czechia, the TSO and DSO are permitted to recover the full allowed return on the value of the CWIP, but only for large projects. In Moldova, the debt interest accumulated during construction is added to the commissioned asset value for the TSO and DSO. Kosovo is the only country to report a distinct approach for the TSO and DSO; the former may recover interest during construction, but the latter is not permitted any return on the value of the CWIP.

Figure 29 How ERRA members treat CWIP, if capex does not enter RAB as spent



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Does capex enter the RAB as spent?	x	✓	x	✓	x	✓	x	x	✓	x	x	x	✓	✓	x	✓	x	x	x	x
No return	✓		✓					✓		✓					✓		?	✓	✓	
Only recover interest during construction							✓										?			✓
Return on asset value												✓					?			
Return on asset value in big projects					✓												?			
Accumulated interest during construction is added to commissioned asset value											✓						?			
DSO																				
Does capex enter the RAB as spent?	x	✓	x	✓	x	✓	x	x	✓	x	x	x	✓	✓	?	✓	x	x	x	x
No return	✓		✓					✓		✓					?		?	✓	✓	✓

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Only recover interest during construction							✓								?		?			
Return on asset value												✓			?		?			
Return on asset value in big projects					✓										?		?			
Accumulated interest during construction is added to commissioned asset value											✓				?		?			

Source: Survey question 4.11. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): For the DSO, Peru explains that the rules have not yet been approved by the Ministry of Energy and Mines, so their approach for dealing with CWIP is currently unclear. For Poland, we were unable to find out their approach for the TSO and DSO.

4.2.5 Working capital

Working capital can be described as the average net amount of capital employed in the regulated firm which is not invested in long-term assets but in various short-term items, such as cash and inventories, and which is required for the day-to-day operations of the business. Where working capital is funded from equity or debt, then this represents a commitment by the owner which should in theory be remunerated.

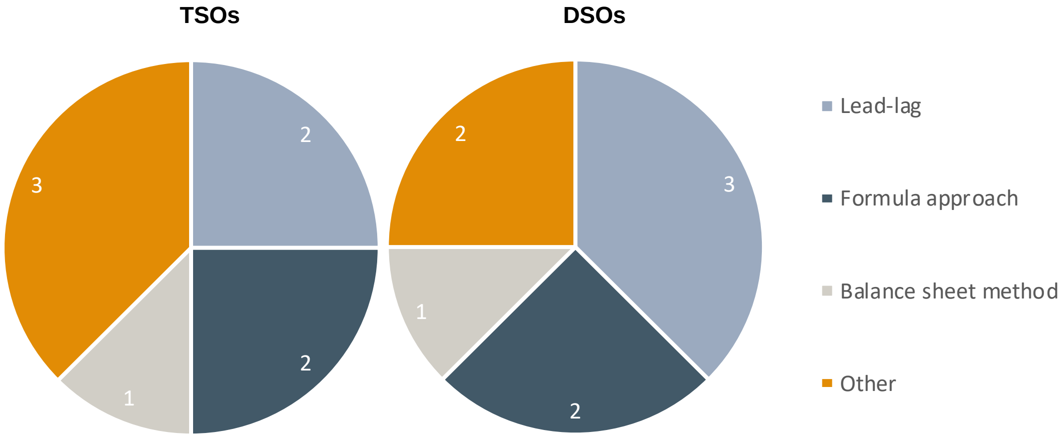
There is no single 'correct' way of calculating working capital for regulatory purposes and there are different options available. The key approaches are the *lead-lag* approach, the *opex* approach; and the *balance sheet* approach (see Table 10).

Table 10 Methods for determining the value of working capital

Method	Description
Lead-lag	▪ The average time difference between when expenses must be paid and when revenue is collected, expressed in days, and multiplied by average daily operating and maintenance expenses.
Formula approach	▪ Sometimes called the 45-day approach, working capital is one-eighth of the utility's annual operating and maintenance expenses (1/8 of a year ≈ 45 days). ▪ Other variants base the calculation on 30 days, 60 days, etc.
Balance sheet	▪ Current assets minus current liabilities, usually excluding interest-bearing short-term deposits and liabilities.

In the ERRA sample, the most common approach for calculating working capital is based on a lead-lag approach (two TSOs and three DSOs), followed by a formula approach (two TSOs and DSOs) and balance sheet (one TSO and DSO) (see Figure 30). Three countries use other approaches. Estonia, for both the TSO and DSO, calculates working capital as 5% of the arithmetic average of the last three calendar years' revenue. Pakistan calculates working capital for the TSO as the sum of 3% of gross fixed assets, one-month revenue requirement, and monthly average cash balance. In Latvia, they set working capital of the TSO and DSO equal to the value of items in stock.

Figure 30 Calculating working capital



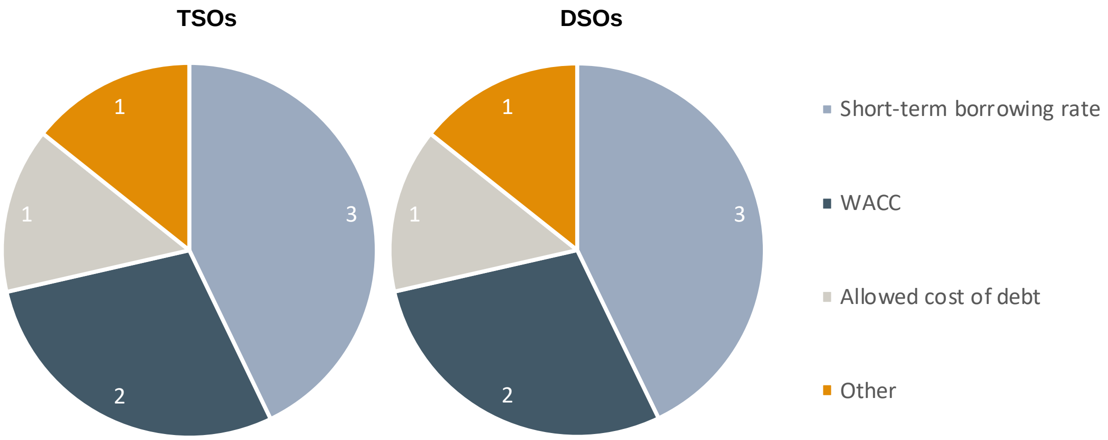
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Is working capital calculated?*	✓	x	x	✓	x	✓	✓	x	x	✓	✓	x	✓	x	✓	✓	x	x	x	✓
Lead-lag							✓				✓				?					?
Formula approach	✓												✓		?					?
Balance sheet method				✓											?					?
Other						✓				✓					?	✓				?
DSO																				
Is working capital calculated?*	✓	x	x	✓	x	✓	✓	x	x	✓	✓	x	✓	x	✓	x	x	x	x	✓
Lead-lag							✓				✓				✓					?
Formula approach	✓												✓							?
Balance sheet method				✓																?
Other						✓				✓										?

Source: Survey question 4.16. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. *For example, is working capital calculated for use in the RAB or opex? Unclear data (?): We were unable to find out the approach for calculating working capital in Kosovo or for Peru's TSO.

When working capital is included in the RAB or opex, the regulator must select a rate at which the utility is remunerated for this amount. The rate selected tends to differ significantly across jurisdictions.

In the ERRA sample, the short-term borrowing rate is the most commonly used rate (three TSOs and DSOs) (see Figure 31). The WACC is used at two TSOs and DSOs. Nigeria uses the allowed cost of debt, determined in the WACC calculation. Pakistan employs the historical cost of debt. A rate set in law is used for the Peruvian DSO.

Figure 31 Rate at which working capital is remunerated



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Is working capital calculated?*	✓	x	x	✓	x	✓	✓	x	x	✓	✓	x	✓	x	✓	✓	x	x	x	✓
Short-term borrowing rate				✓		?	✓			✓					?					?
WACC	✓					?					✓				?					?
Allowed cost of debt						?							✓		?					?
Other						?									?	✓				?
DSO																				
Is working capital calculated?*	✓	x	x	✓	x	✓	✓	x	x	✓	✓	x	✓	x	✓	x	x	x	x	✓
Short-term borrowing rate				✓		?	✓			✓										?
WACC	✓					?					✓									?
Allowed cost of debt						?							✓							?
Other						?									✓					?

Source: Survey question 4.17. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. *For example, is working capital calculated for use in the RAB or opex? Unclear data (?): We were unable to find out the rate at which working capital is remunerated in Estonia and Kosovo and at Peru's TSO.

4.2.6 Asset value

If a jurisdiction moves from a regime that *does not* use a RAB to a new regime that *does* use a RAB in its methodology, then the regulator must determine an appropriate opening value for the assets in the RAB. The three broad approaches are *historical cost*, *current value*, and *replacement cost* (see Table 11).

In practice, regulators may adopt a mix of these approaches.

Table 11 Methods for determining asset value

Method		Description
Historical cost		▪ The cost of acquiring the asset in the past minus its cumulative depreciation. ▪ Also referred to as depreciated actual cost. ▪ This may also be indexed to inflation.
Current (or economic) value	Economic value	▪ The present value of future net cash flows expected to be generated by the asset.
	Deprival value	▪ The lesser of the economic value and the replacement cost (see below).
Replacement cost	Modern equivalent asset	▪ The cost of replacing the asset with another asset capable of providing the same services, adjusting for depreciation to reflect the asset's remaining useful life.
	Like-for-like	▪ The cost of purchasing the same asset, adjusting for depreciation to reflect the asset's remaining useful life.
	Optimised	▪ The cost of replacing the asset with another capable of providing the same services more efficiently, adjusting for depreciation to reflect the asset's remaining useful life.
Privatisation value		▪ The value set or implied by the privatisation of the regulated entity.
Long-run incremental cost (LRAIC)		▪ The change in the total long-run cost resulting from the additional asset.

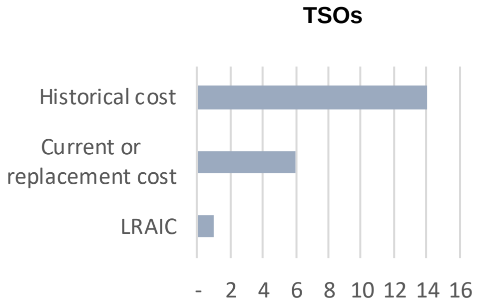
Source: ECA

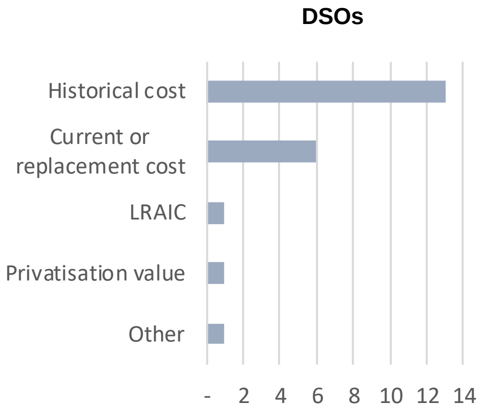
In some cases, regulators might choose instead to adopt a forward-looking approach to revenue setting that incorporates projected changes in electricity demand in relation to existing network capacity and future incremental investments needed to meet rising demand. The full elaboration of this approach is for tariffs to be based on long-run marginal costs or its approximation, **long-run average incremental cost (LRAIC)**, which is the present value of the additional investment and operating costs associated with meeting a sustained incremental increase in demand.

Since marginal or incremental costs may well be less than average costs for electricity networks which are characterised by strong economies of scale, setting tariffs purely based on LRAIC may not provide enough revenue for financial viability. Hence, LRAIC is normally used for tariff *design* rather than revenue setting (with tariffs then scaled to the level of allowed revenues).

In the ERRA sample, **the most common approach for determining the opening asset value is historical cost** (14 TSOs and 13 DSOs), followed by current or replacement cost (six TSOs and DSOs) (see Figure 32). Lithuania uses LRAIC for both its TSO and DSO. Austria uses multiple approaches, including the privatisation value. In Turkey, the opening asset value for the DSO was set to zero (so the network businesses were only permitted a return on forward investment).

Figure 32 Determining opening asset value





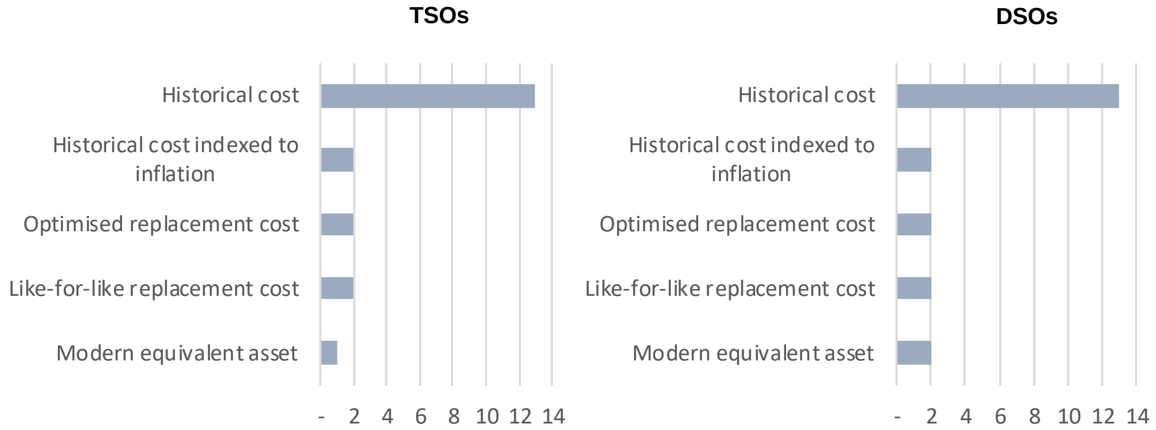
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Historical cost	✓	✓	✓	✓	✓	✓	✓			✓		✓		✓		✓	✓	✓	✓	
Current or replacement cost		✓						✓			✓		✓		✓					✓
LRAIC									✓											
DSO																				
Historical cost	✓	✓	✓	✓	✓	✓	✓			✓		✓		✓		✓	✓	✓		
Current or replacement cost		✓						✓			✓		✓		✓					✓
LRAIC									✓											
Privatisation value		✓																		
Other																			✓	

Source: Survey question 4.12. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

If a jurisdiction already adopts a RAB-based regime, the historical purchase or construction price of assets will deviate from their replacement cost over time. The replacement costs will, in most cases, eventually exceed the historical cost. It may also be that the configuration of assets becomes no longer (or never was) optimal to meet demand, meaning that customers are paying for assets that are not required to provide the given service. This opens the question of whether to revalue the RAB at regular intervals and to then use these new values as the RAB going forward.

In the ERRA sample of TSOs, **the most common approach for revaluing the RAB is using historical cost** (13 TSOs and DSOs) (see Figure 33). Historical cost indexed to inflation and optimised and like-for-like replacement cost approaches are each adopted by two TSOs and DSOs. The modern equivalent assets approach is adopted by only one TSO (Slovakia) and two DSOs (Slovakia and Peru). In broader terms, 15 TSOs and DSOs use historical cost with or without inflation indexation, five TSOs and six DSOs use an approach based on replacement cost, and none use an approach based on current value.

Figure 33 Periodically revaluing asset values



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
Historical cost	✓	✓	✓	✓	✓	✓	✓				✓	✓			✓	✓	✓			✓
Historical cost indexed to inflation														✓					✓	
Optimised replacement									✓				✓							
Like-for-like replacement								✓		✓										
Modern equivalent asset																		✓		
DSO																				
Historical cost	✓	✓	✓	✓	✓	✓	✓				✓	✓		✓		✓	✓			✓
Historical cost indexed to inflation														✓					✓	
Optimised replacement									✓				✓							
Like-for-like replacement								✓		✓										
Modern equivalent asset															✓			✓		

Source: Survey question 4.13. Red marks indicate a divergence between the TSO and DSO method. [†]See Footnote 2.

4.2.7 Depreciation

The use of depreciation is intended to spread the cost of investments out across their useful lives. Theoretically, an alternative approach would be to allow the utility to fully recover the costs of its capital expenditure in the year in which it occurs, but this would place the full cost burden on customers in that year, when in fact the investment is likely to benefit both present and future customers for many years to come. The most common methods for calculating depreciation are provided in Table 12.

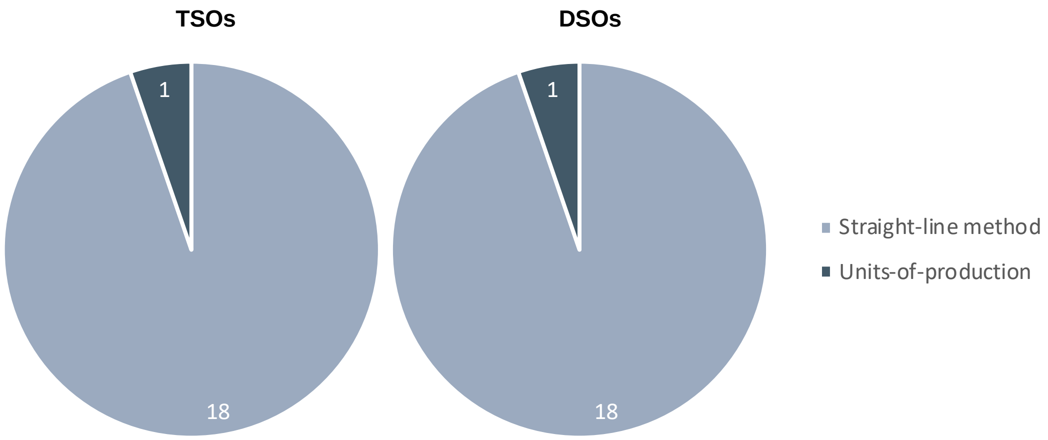
Table 12 Methods for calculating depreciation

Method	Description
Straight-line	▪ The opening asset value is divided by the asset life to determine annual depreciation. ▪ Thus, the asset depreciates in a straight line to reach a value of zero at the anticipated time of decommissioning.
Accelerated	▪ Calculated annual depreciation of an asset is higher in the initial years and lower closer to the time of decommissioning.
Units-of-production	▪ The annual depreciation of the asset is proportional to the number of units produced by the asset in that year.

Source: ECA

In the ERRA sample, **the overwhelming majority use straight-line deprecation** (18 TSOs and DSOs) (see Figure 34). Only Slovakia adopts a units-of-production approach for their TSO and DSO, and no respondents adopt an accelerated approach (see Figure 34).

Figure 34 Methods of depreciation



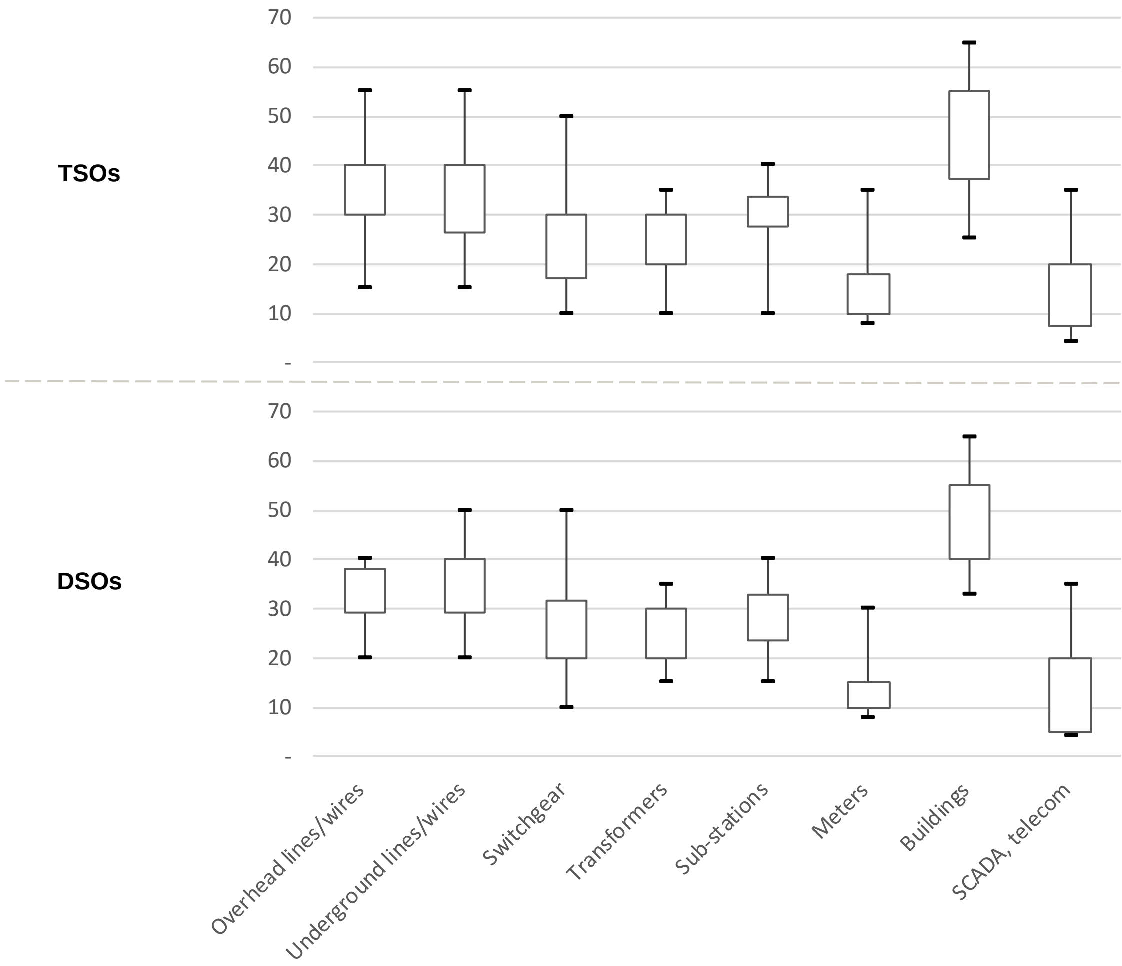
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Straight-line	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	?		✓	✓
Units-of-production																	?	✓		
DSO																				
Straight-line	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	?		✓	✓
Units-of-production																	?	✓		

Source: Survey question 4.18. †See Footnote 2. Unclear data (?): We were unable to find out what approach Poland uses for depreciating the value of assets.

Because it is important that depreciation reflect the costs of investments across their useful lives, economic asset lives are generally used rather than accounting asset lives. Accounting lives are generally set for constructing statutory financial accounts and for tax reasons and, in the past, might have borne little resemblance to the actual useful lives of assets.

In the ERRA sample, **the average life for different asset categories varies significantly across respondents**. Figure 35 displays box-and-whisker plots for the asset life used for different asset categories by the TSO and DSO in each country. For each country, the data provided are the weighted average asset life for each category.

Figure 35 Average asset lives (years)



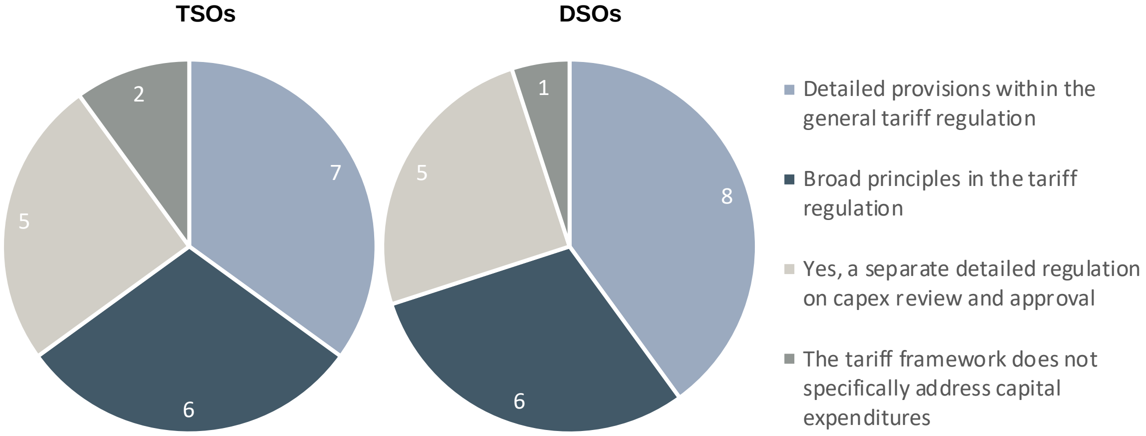
Source: Survey question 4.19. Chart displays maximum, minimum, upper quartile, and lower quartile.

4.2.8 Capex in law

Above, **we have discussed the approaches to reviewing, assessing, and approving capex. The authority for these rules depends on how or whether they are specified in law**. If there are detailed provisions within the general tariff regulations, the authority sits with the entities constructing this primary or secondary legislation (parliament, government, or the regulator). Similarly, there may be a separate regulation for capex to ensure that provisions leave little room for ambiguity and interpretation. If there are provisions within the general tariff regulation, but the principles are broad, the regulator has greater flexibility in interpreting the rules. If the tariff framework does not specifically address rules on capex, then regulatory staff are left to decide these matters for themselves.

In the ERRA sample, **the most common approach for outlining rules on reviewing, assessing and approving capex is to include them as detailed provisions within the general tariff regulation** (seven TSOs and eight DSOs) (see Figure 36). Six countries outline them only as broad principles within the general tariff regulation for their TSOs and DSOs. Five have a separate detailed regulation for this purpose for their TSOs and DSOs. In two TSO and one DSO regime, the tariff regulation does not specifically address such rules.

Figure 36 Rules on capex



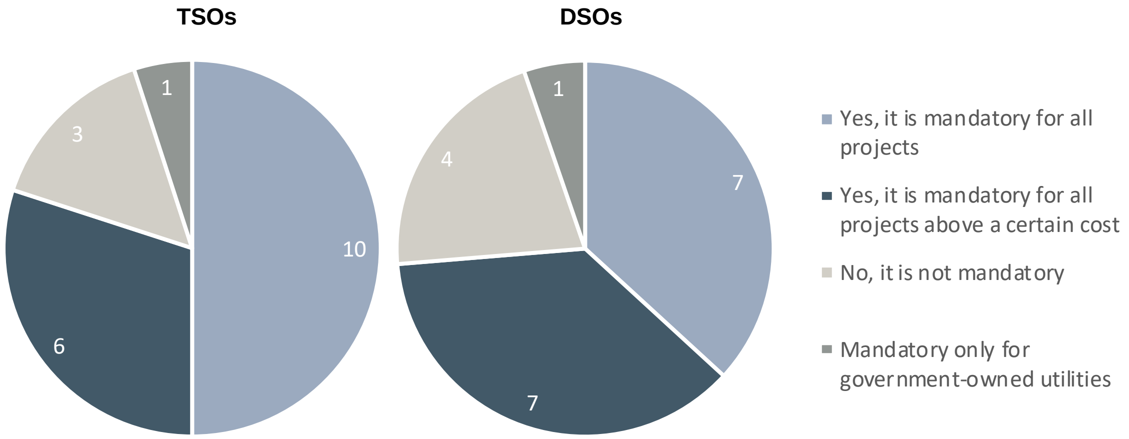
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
Detailed provisions in tariff method		✓				✓	✓	✓	✓	✓		✓								
Broad principles in tariff method			✓	✓	✓								✓			✓			✓	
Separate regulation	✓										✓			✓	✓					✓
Framework does not address capex method																	✓	✓		
DSO																				
Detailed provisions in tariff method		✓				✓	✓	✓	✓	✓		✓					✓			
Broad principles in tariff method			✓	✓	✓								✓		✓	✓				
Separate regulation	✓										✓			✓					✓	✓
Framework does not address capex method																		✓		

Source: Survey question 4.1. Red marks indicate a divergence between the TSO and DSO method. [†]See Footnote 2.

4.2.9 Tendering capex

In the ERRA sample, **the most common approach is to make it mandatory to tender all investment projects competitively** (ten TSOs and seven DSOs) (see Figure 37). For six TSOs and seven DSOs, it is mandatory only for projects above a certain cost. For three TSOs and four DSOs, it is not mandatory. In Georgia, it is only mandatory for government-owned utilities.

Figure 37 Tendering capex



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
Mandatory for all projects				✓		✓		✓	✓				✓		✓	✓	✓	✓		✓
Mandatory for projects above a certain cost		✓								✓	✓	✓		✓					✓	
Not mandatory	✓		✓		✓															
Mandatory only for government-owned utilities							✓													
DSO																				
Mandatory for all projects				✓		✓			✓				✓			✓	?	✓		✓
Mandatory for projects above a certain cost		✓						✓		✓	✓	✓		✓			?		✓	
Not mandatory	✓		✓		✓										✓		?			
Mandatory only for government-owned utilities							✓										?			

Source: Survey question 4.6. Red marks indicate a divergence between the TSO and DSO method. [†]See Footnote 2. Unclear data (?): We were unable to find out Poland's approach for the DSO.

4.3 WACC

The weighted average cost of capital (WACC) is the percentage return a utility is permitted on its RAB. It is the weighted average of the cost of debt and cost of equity, weighted by the share of debt and equity in the utility's capital structure, respectively. There are variations in the definition which hinge on their inclusion of corporation taxes and inflation.

Below, we present the regulatory approaches to WACC in each jurisdiction. Details of the calculations used to produce the graphs in this section can be found in Annex A1.

4.3.1 Tax and inflation

It is the *real* return on the RAB that motivates investment. There are two key approaches to disentangling inflation from nominal returns. One is to multiply the RAB (which is typically in nominal costs) by the nominal WACC (which includes inflation). In a *nominal WACC*, the values for the cost of equity and debt are nominal. An alternative approach is to index the RAB to inflation and multiple by the *real WACC* (ie excluding inflation), in which the cost of equity and debt are real.

Furthermore, **investors are concerned primarily with their *after-tax* returns**. There are two ways to dealing with tax in a WACC context. One is to multiply the cost of equity by a 'tax wedge' to determine its pre-tax value, which produces a *pre-tax WACC*. Alternatively, the regulator could calculate a separate allowance for tax on profits as a separate amount in the composition of the allowed revenues and use a *vanilla or post-tax WACC*. These variations are displayed in Table 13.

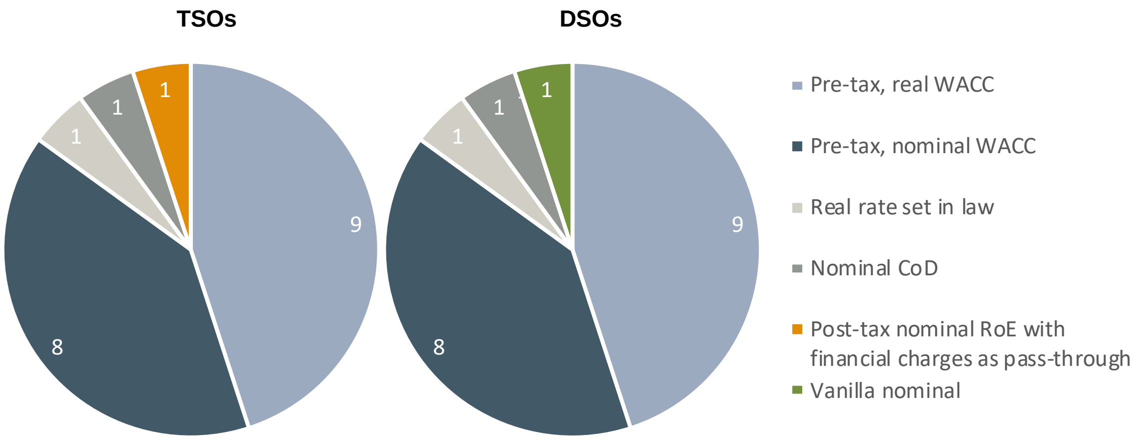
Table 13 Tax in the WACC

Method	Description
Pre-tax	$WACC = g \cdot CoD + (1-g) \cdot CoE \cdot \frac{1}{1-\tau}$ where CoD is the cost of debt, CoE is the (after-tax) cost of equity, g is the gearing rate (the level of debt divided by the sum of debt and equity), and τ is the corporate tax rate on profits.
Vanilla	$WACC = g \cdot CoD + (1-g) \cdot CoE$ this computation does not apply the tax wedge and therefore allows for a post-tax cost of equity (and thus a post-tax WACC) but requires that a separate allowance be made for tax on profits as a separate amount in the composition of the allowed revenues
Post-tax	$WACC = g \cdot CoD \cdot (1-\tau) + (1-g) \cdot CoE$ with this method, the cost of debt is multiplied by the factor $(1 - \tau)$ to capture the tax benefit associated with gearing (as interest is deducted before tax is calculated). When using this approach, care is needed in calculating tax allowances, as the tax deductibility of interest costs is already captured in the WACC formula (ie interest costs should therefore be excluded from the calculation of the tax building block of the revenue equation)

Source: ECA

In the ERRA sample, the **most common approach for setting the WACC is pre-tax real (nine TSOs and DSOs), followed closely by pre-tax nominal (eight TSOs and DSOs)** (see Figure 38). Peru uses a real rate set in law for both the TSO and DSO. For the TSO, Pakistan uses a post-tax nominal return on equity, setting financial charges as pass-through costs; for the DSO, Pakistan uses a nominal vanilla WACC. For the TSO and DSO, Azerbaijan uses a pre-tax nominal WACC with 0% return on equity, since their government owns 100% of equity, meaning the return on capital is simply the nominal cost of debt. Thus, only Pakistan explicitly uses a WACC including a post-tax return on equity, and the overwhelming majority use a pre-tax WACC.

Figure 38 Basis on which ERRA members set the WACC

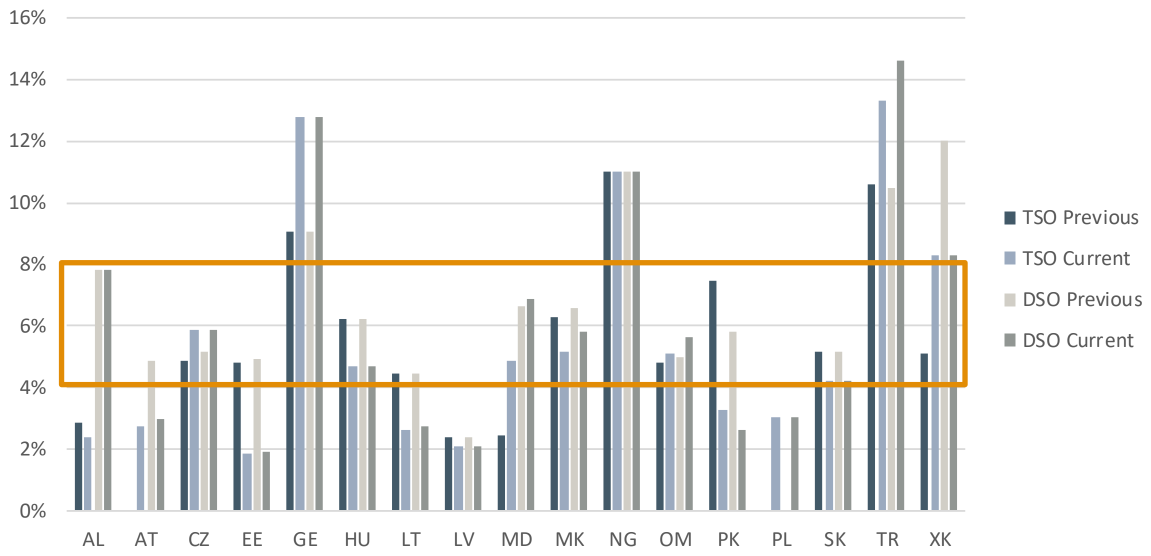


	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Pre-tax real	✓			✓				✓				✓	✓	✓			✓		✓	✓
Pre-tax nominal		✓			✓	✓	✓		✓	✓	✓							✓		
Real rate set in law															✓					
Nominal CoD			✓																	
Post-tax nominal RoE with financial charges as pass-through																✓				
DSO																				
Pre-tax real	✓			✓				✓				✓	✓	✓			✓		✓	✓
Pre-tax nominal		✓			✓	✓	✓		✓	✓	✓							✓		
Real rate set in law															✓					
Nominal CoD			✓																	
Vanilla nominal																✓				

Source: Survey question 5.1. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

In Figure 39, we present the pre-tax real WACC of ERRA TSOs and DSOs in the current and previous regulatory period. For regimes that use a nominal WACC, we deflate the WACC using the average annual inflation rate for that period. As shown in the figure, there is considerable variation among countries, although **in most cases, the real WACC sits within the 4%-8% range**.

Figure 39 Pre-tax real WACC



Source: ECA calculations in Annex A1 based on survey question 5.9. Note PK is vanilla real WACC.

4.3.2 Cost of debt

The cost of debt is the interest payable to lenders. The regulator could:

- pass through actual interest costs, or
- calculate the interest cost *ex-ante* and incorporate it into a WACC formula.

In the latter case (ie under a WACC approach), the utility bears the difference between the allowed and actual interest costs, which incentivises it to borrow or re-finance efficiently. However, it also provides greater risk of losses. There are alternative approaches to determining the cost of debt in this approach, described in Table 14.

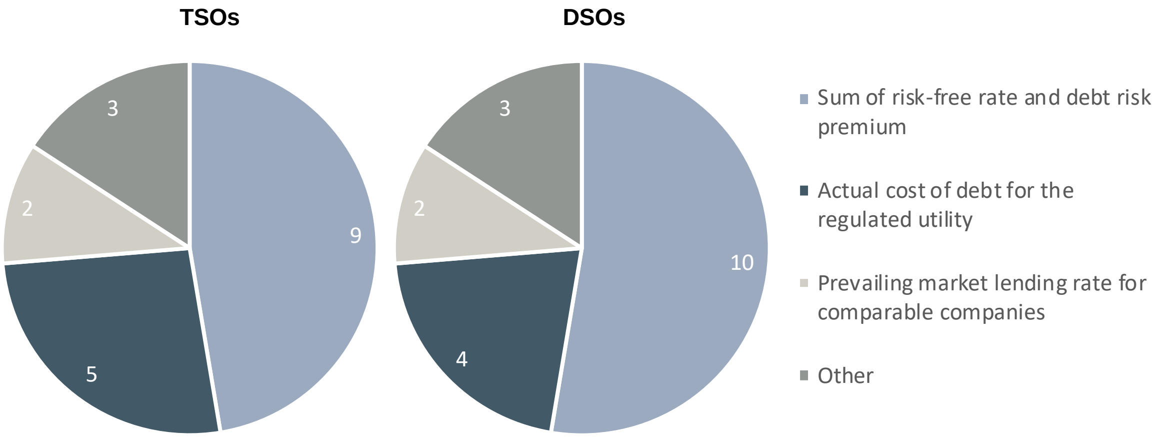
Table 14 Methods for determining the cost of debt

Method	Description
Market-based estimates	▪ $CoD = RFR + DP$ ▪ The risk-free rate (RFR), discussed below, is the rate of return that could be gained from a risk-free investment. ▪ The debt premium (DP) is based on the utility's credit rating.
Embedded estimates	▪ The utility's historical cost of debt in financial accounts.
Benchmarking	▪ Prevailing market lending rate for comparable utilities.

Source: ECA

In the ERRA sample, **the most common approach is market-based, ie the sum of the risk-free rate and debt risk premium** (nine TSOs and ten DSOs) (see Figure 40). Five TSOs and four DSOs use embedded estimates based on the utility's actual cost of debt. Two TSOs and DSOs use benchmarking based on the market lending rate for comparable utilities. The remaining respondents use unique approaches. Latvia determines the cost of debt for its TSO and DSO as the average interest rate issued to non-financial corporations in the country in the last ten years. Lithuania uses the actual cost of the debt for the utility, capped at the market interest rate. Moldova determines the cost of debt annually, equating it to the average rate on credits granted in foreign currency in the year of the tariff calculation, based on the figures published by the central bank.

Figure 40 Approaches for determining cost of debt



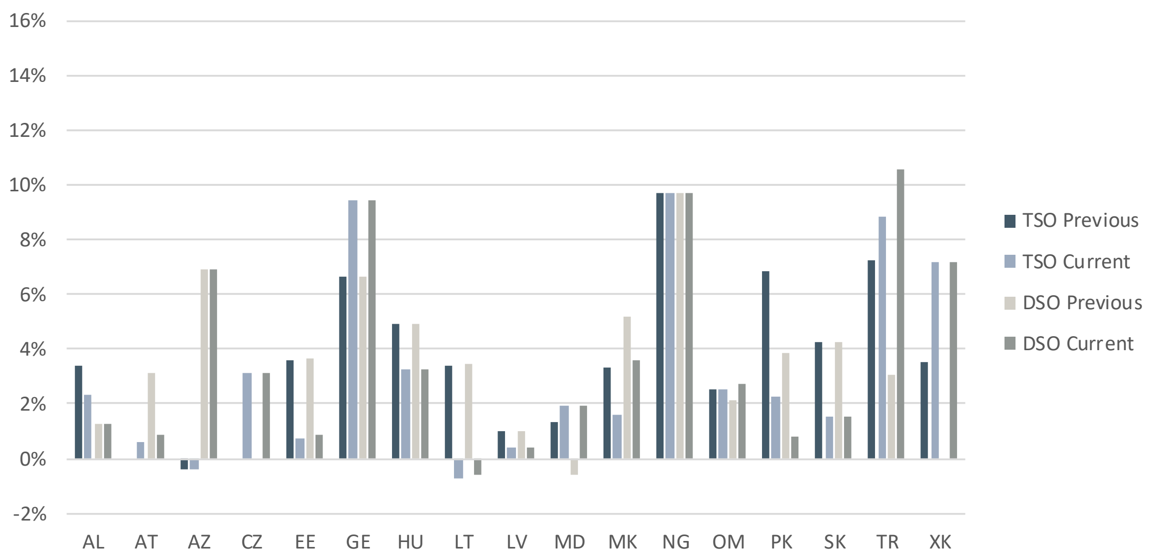
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Is CoD calculated?	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Sum of risk-free rate and debt risk premium		✓			✓	✓		✓					✓	✓			✓		✓	✓
Actual cost of debt for the regulated utility	✓		✓	✓								✓				✓				
Market lending rate for comparable companies							✓											✓		
Other									✓	✓	✓									
DSO																				
Is CoD calculated?	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Sum of risk-free rate and debt risk premium		✓			✓	✓		✓					✓	✓		✓	✓		✓	✓

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Actual cost of debt for the regulated utility	✓		✓	✓								✓								
Market lending rate for comparable companies							✓											✓		
Other									✓	✓	✓									

Source: Survey question 5.2. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

In Figure 41, we present the real cost of debt of ERRA TSOs and DSOs in the current and previous regulatory period. We deflate any nominal values using the average annual inflation rate for that period. Again, there is **considerable variation in allowed debt costs, which is to be expected given the dependence of lending costs on country and firm circumstances**.

Figure 41 Real cost of debt



Source: ECA calculations in Annex A1 based on survey question 5.9

4.3.3 Cost of equity

The cost of equity is the opportunity cost of using the equity in the investment rather than in other ventures. It is the return that the equity could earn in other projects. It therefore represents the rate of return necessary to attract equity finance. Some of the approaches to estimating the cost of equity are described in Table 15.

Table 15 Methods for determining the cost of equity

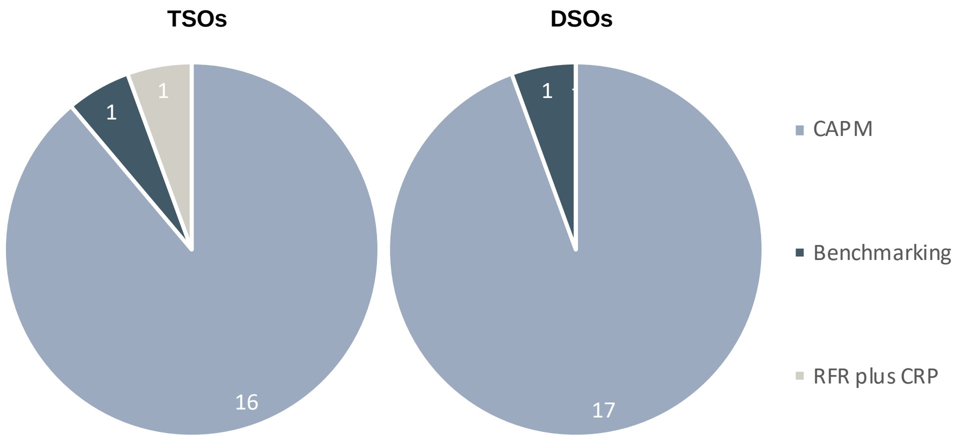
Method	Description
Capital asset pricing model (CAPM)	▪ $CoE = RFR + ERP \cdot \beta_E$

Method	Description
	▪ The risk-free rate (RFR), discussed below, is the return that could be earned from a risk-free investment. ▪ The equity risk premium (ERP) is an additional return, on top of the risk-free rate, expected in a balanced portfolio of investments in the investment market. (This is also referred to as the market risk premium.) ▪ The equity beta (β_E) is the extent to which the investment's returns and the returns from the wider market are expected to co-vary.
Dividend growth model	▪ The cost of equity is the present value of the dividends that would be earned each year by investing the equity elsewhere.
Benchmarking	▪ The cost of equity adopted by comparable utilities.
Investor survey	▪ This requires surveying investors or equity analysts about their view or estimate of the required return on equity. However, such methods are generally considered to be unreliable and are therefore rarely used or are limited to aiding understanding of factors associated with the ERP

Source: ECA

In the ERRA sample, **the overwhelming majority use the capital asset price model (CAPM) for determining cost of equity** (16 TSOs and 17 DSOs) (see Figure 42). None use the dividend growth model or an investor survey. For the TSO's cost of equity, Moldova uses the risk-free rate plus a country risk premium (CRP); for the DSO, it uses the CAPM. Bulgaria uses benchmarking for both its TSO and DSO.

Figure 42 Approaches to determining the cost of equity



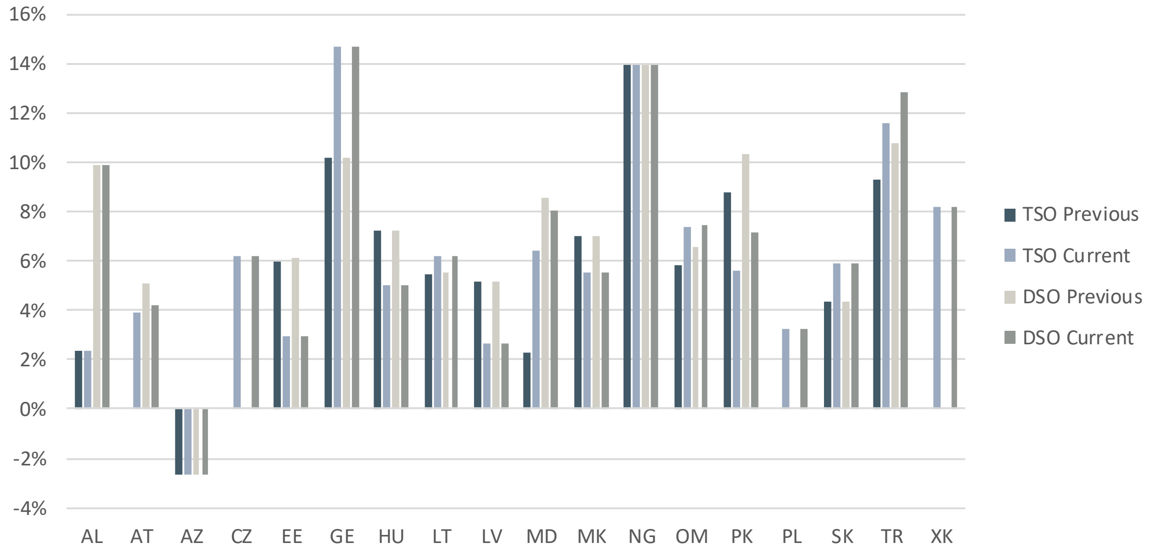
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Is CoE calculated?	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
CAPM	✓	✓			✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	✓	✓	✓	✓
Benchmarking				✓																
RFR plus CRP											✓									
DSO																				
Is CoE calculated?	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
CAPM	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Benchmarking				✓																

Source: Survey question 5.5. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

In Figure 43, we present the real cost of equity of ERRA TSOs and DSOs in the current and previous regulatory period. We deflate any nominal values using the average annual inflation rate for that period. As with all WACC parameters, one can observe considerable variation across countries.

Figure 43 Real cost of equity



Source: ECA calculations in Annex A1 based on survey question 5.9

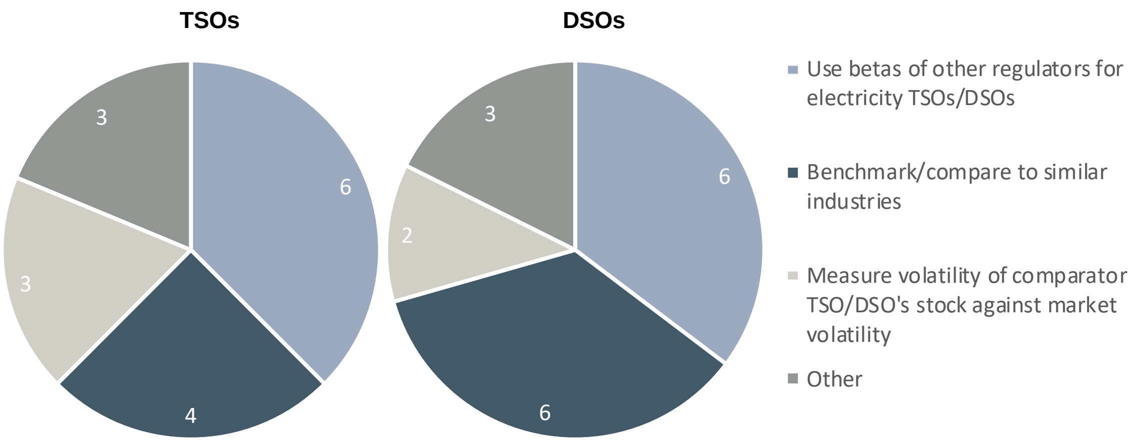
4.3.4 Equity beta

In the CAPM approach to estimating the cost of equity, the equity beta (β_E) is a measure of risk associated with a specific investment relative to the market (of all investable assets). **The beta indicates how responsive an investment is to movements in the wider market**. An equity beta less than one means an investment is less risky than the market and a lower return is appropriate; an equity beta greater than one means an investment is riskier than the market and a higher return is appropriate.

If the utility is a listed company, the equity beta can be measured as the covariance between the utility's share price and the wider equity market (proxied by a benchmark index). However, many utilities are not listed and therefore do not have a public share price; in these cases, regulators often use the betas of comparable listed companies. Alternatively, the regulator could simply use the beta parameters determined by other regulators for comparable utilities.

In the ERRA sample, **the most common approach is to use the equity beta of other electricity regulators** (six TSOs and DSOs) **or to benchmark against similar industries** (four TSOs and six DSOs). Three TSOs and two DSOs measure the volatility of comparator TSO companies' stocks against market volatility. Nigeria fixes the equity beta for its TSO and DSO at zero, stating a lack of benchmarking data for similar industries; this effectively sets the cost of equity equal to the RFR. Conversely, North Macedonia fixes the equity beta of the TSO and DSO at one, again due to a lack of benchmarking data; they state that they use this value because expected return should equal the market return. Kosovo also sets its TSO and DSO equity beta at one, based on the regulator's own judgement. While Albania claims to use a CAPM approach for the determination of the cost of equity, they state that 'there is no beta predicted in the methodology'; it is unclear what value they use for the beta in their CAPM equation.

Figure 44 Approaches for determining equity betas



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
CAPM used?	✓	✓	x	x	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	x	✓	✓	✓	✓	✓
Betas of other power TSOs	?						✓		✓	✓				✓		✓	?		✓	
Benchmark similar industries	?					✓		✓									?	✓	✓	
Volatility of comparator TSO/DSO's stock against market volatility	?	✓			✓											✓	?			
Other	?											✓	✓				?			✓
DSO																				
CAPM used?	✓	✓	x	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Betas of other power DSOs	?						✓		✓	✓				✓		✓	?		✓	
Benchmark similar industries	?					✓		✓			✓					✓	?	✓	✓	
Volatility of comparator TSO/DSO's stock against market volatility	?	✓			✓												?			

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Other	?											✓	✓				?			✓

Source: Survey question 5.6. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): We understand that Albania and Poland use a CAPM approach for calculating the cost of equity. However, Albania states there is 'no beta predicted in the methodology', so it is unclear what approach they use for determining the equity beta. We were unable to find out how Poland calculates its equity beta.

In making this comparison, regulators typically adjust the equity beta to take account of different levels of gearing between the listed and unlisted firms. This is because higher gearing results in a higher equity beta. To adjust for differences in gearing, regulators use the equity beta and gearing of the listed company to calculate **an 'asset' beta, which is a construct intended to measure beta assuming no debt (deleveraging)**. This asset beta is then leveraged using the gearing level of the unlisted firm. An asset beta cannot be observed, and therefore must be derived from observed equity betas.

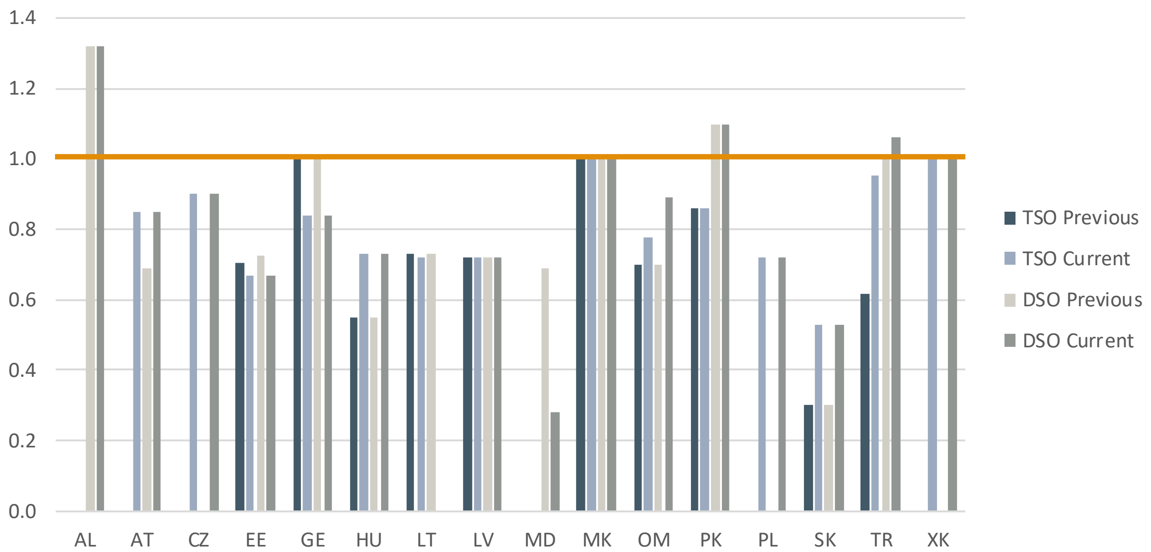
The formula typically used for leveraging and deleveraging betas is below. The tax term is usually omitted and, often, the debt beta is assumed to be zero (a reasonable assumption for investment grade debt, but less realistic otherwise).

$$\beta_E = \beta_A + (\beta_A - \beta_D) \cdot (1 - \tau) \cdot g$$

where: β_A is the asset beta, β_E is the equity beta, β_D is the debt beta, g is gearing, and τ is the corporate tax rate.

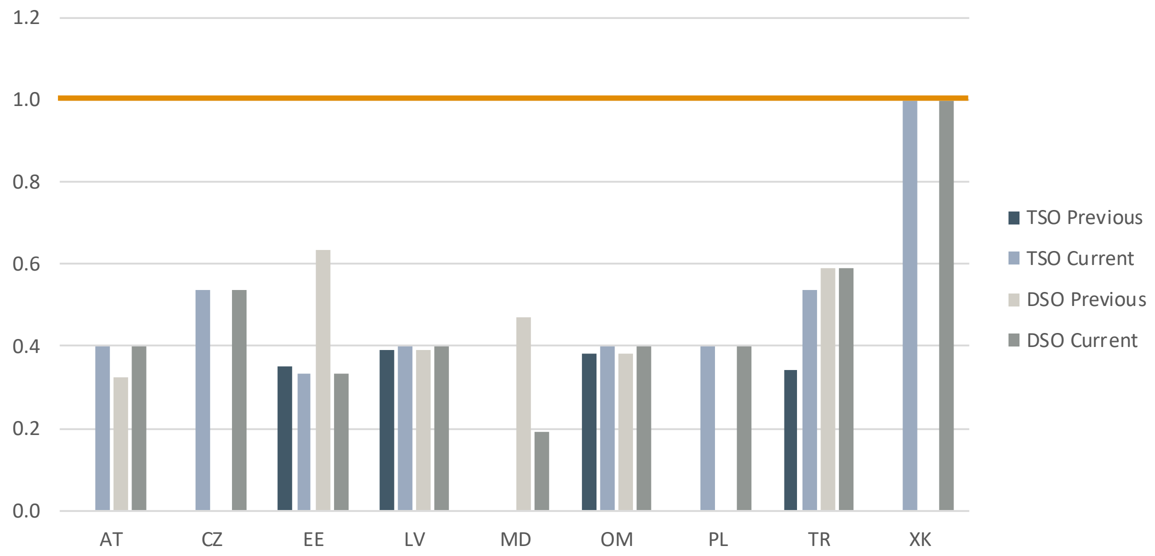
In Figure 45 and Figure 46, we present the equity and asset betas, respectively, of ERRA TSOs and DSOs in the current and previous regulatory periods. As shown in the figure, equity betas are mostly (although not exclusively) less than one; only Albania, Pakistan, and Turkey report a value of greater than one in some cases, implying a degree of risk.

Figure 45 Equity betas



Source: Survey question 5.9

Figure 46 Asset betas



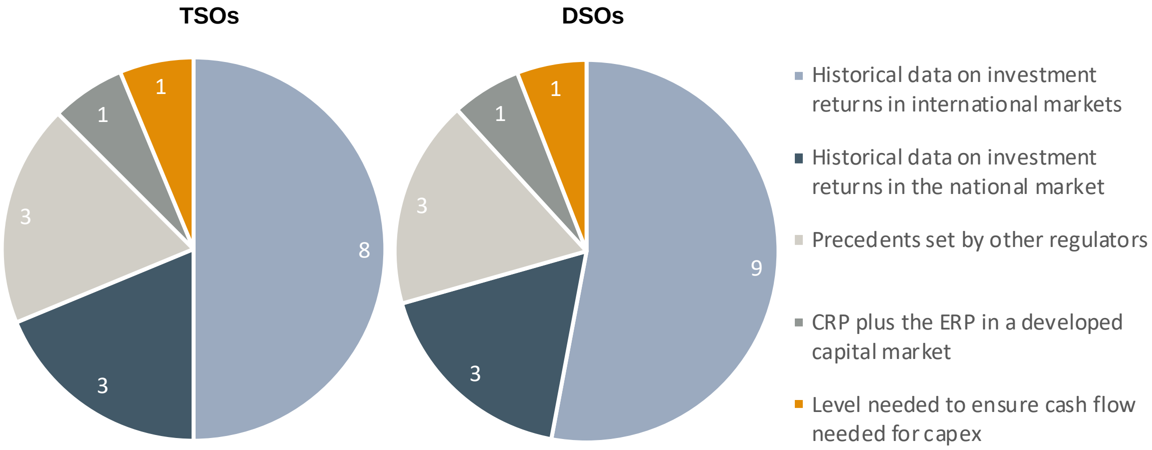
Source: Survey question 5.9

4.3.5 Equity risk premium

In the CAPM approach to estimating the cost of equity, regulators typically use historical data reflecting actual investment returns in international or national markets, or precedents set by other regulators, to measure the equity risk premium.

In the ERRA sample, **for the majority of TSOs and DSOs where the regulator adopts a CAPM approach for the cost of equity, historical data is used reflecting actual investment returns to estimate the equity risk premium** (11 TSOs and 12 DSOs) (see Figure 47). For eight TSOs and nine DSOs, historical data is used reflecting investment returns in the international market, and for three TSOs and DSOs the equivalent data from the national market is used. For three TSOs and DSOs, precedents set by other regulators are used. Lithuania uses an approach of summing the equity risk premium in the US (ie a developed capital market) and Lithuania's country risk premium (CRP). Albania simply chooses an equity risk premium that ensures the cash flow needed for capex.

Figure 47 Approaches for determining the equity risk premium



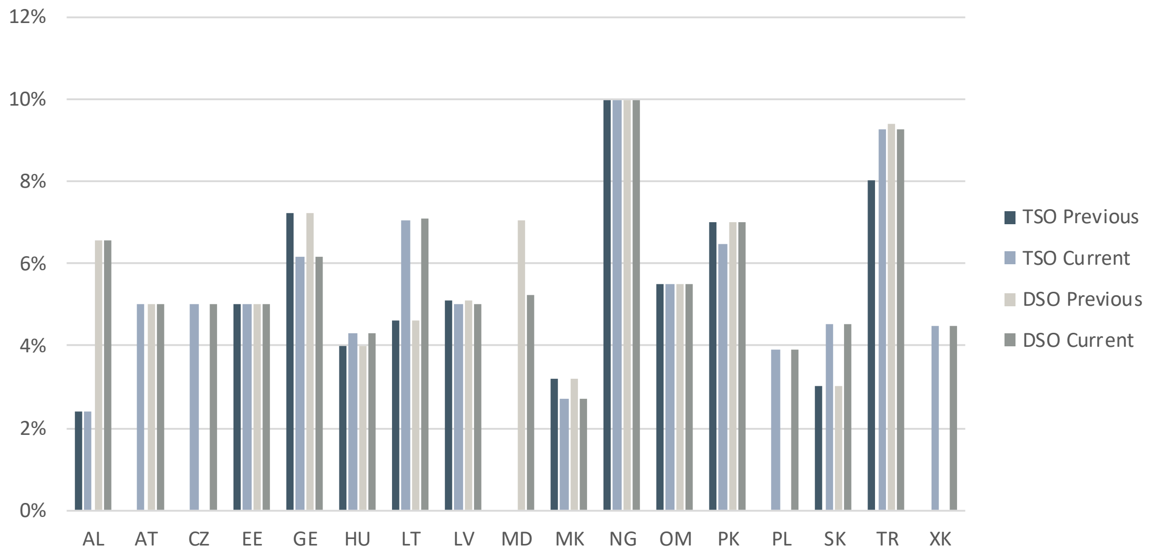
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
CAPM used?	✓	✓	x	x	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	x	✓	✓	✓	✓	✓
Historical data on investment returns in international markets		✓			✓	✓	✓	✓					✓					✓	✓	
Historical data on investment returns in the national market												✓				✓	✓			
Precedents set by other regulators										✓				✓						✓
CRP plus the ERP in a developed capital market									✓											
Level needed to ensure cash flow needed for capex	✓																			
DSO																				
CAPM used?	✓	✓	x	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Historical data on investment returns in international markets		✓			✓	✓	✓	✓			✓		✓					✓	✓	
Historical data on investment returns in the national market												✓				✓	✓			

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Precedents set by other regulators										✓				✓						✓
CRP plus the ERP in a developed capital market									✓											
Level needed to ensure cash flow needed for capex	✓																			

Source: Survey question 5.8. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2.

In Figure 48, we present the equity risk premiums reported by ERRA TSOs and DSOs in the current and previous regulatory periods.

Figure 48 Equity risk premiums



Source: Survey question 5.9

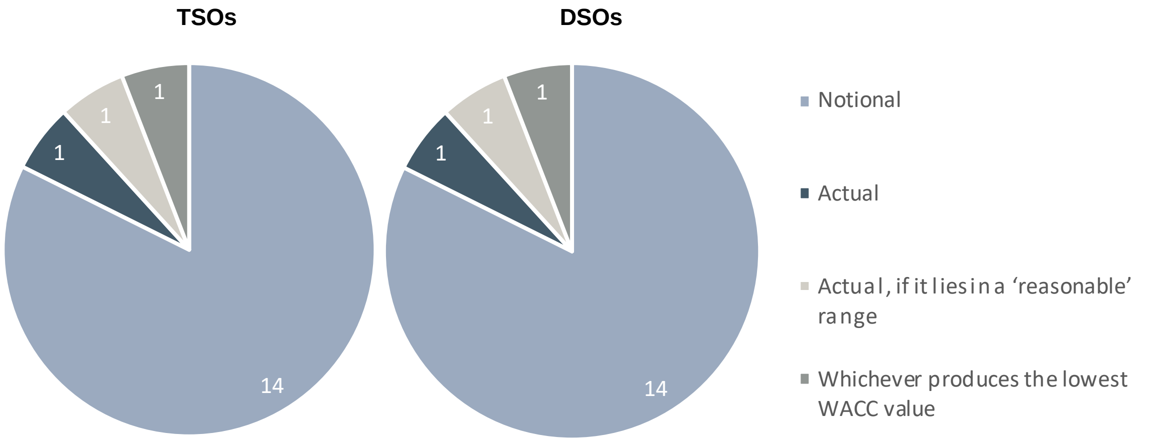
4.3.6 Gearing ratio

There are two main options for setting gearing in the WACC. If ***actual*** **gearing** is used, then the regulator uses the actual capital structure of the company as it is currently or is expected to stand over the regulatory period. If ***notional*** **gearing** is used, then the regulator uses what may be considered a typical, objective, or efficient capital structure without regard to the actual capitalisation of the utility.

A common claim is that, as debt is cheaper than equity, higher gearing will reduce the WACC. However, this overlooks the interaction between gearing and the equity beta. If a company increases its gearing, the business risk will be more concentrated on a smaller value of equity, and shareholders will require higher rates of return (the equity beta will increase). This will offset, at least partially, the greater weight placed on debt.

In the ERRA sample, **the majority use a notional gearing ratio** (14 TSOs and DSOs) (see Figure 49). Albania uses actual gearing for the TSO and DSO. Bulgaria uses the actual gearing ratio, provided it lies in a 'reasonable range', for its TSO and DSO. For Lithuania's TSO and DSO, the ratio is chosen to produce the lowest possible WACC value.[17] For Azerbaijan, the gearing ratio is irrelevant, because the entity only pays for the cost of debt, since the government owned 100% of equity, and the return on equity is 0%.

Figure 49 Approaches for determining the gearing ratio



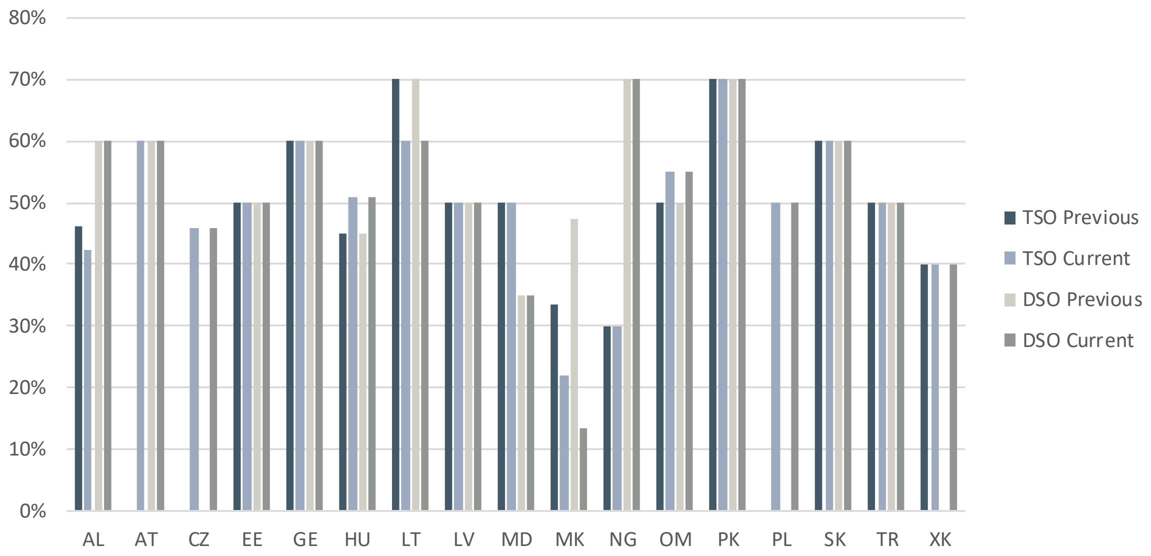
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Gearing used in WACC?	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Notional		✓			✓	✓	✓	✓		✓	✓	✓	✓	✓		✓	?	✓	✓	✓
Actual	✓																?			
Actual, if in a 'reasonable' range				✓													?			
Whichever produces the lowest WACC									✓								?			
DSO																				
Gearing used in WACC?	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Notional		✓			✓	✓	✓	✓		✓	✓	✓	✓	✓		✓	?	✓	✓	✓
Actual	✓																?			
Actual, if in a 'reasonable' range				✓													?			
Whichever produces the lowest WACC									✓								?			

Source: Survey question 5.4. †See Footnote 2. Unclear data (?): We were unable to find out what approach Poland uses for determining the gearing ratio in the WACC for its TSO and DSO.

[17] They do not explain how they select a gearing ratio that minimises the WACC.

In Figure 50, we present the gearing ratio used by ERRA TSOs and DSOs in their WACC calculations in the current and previous regulatory periods. Most of these are in the 40-50% range.

Figure 50 Gearing ratios



Source: Survey question 5.9

4.3.7 Risk-free rate

The risk-free rate is the return an investor would expect to receive from an investment with zero risk over a given period. As risk-free assets are merely an abstract concept, the RFR is typically proxied by the yield on government borrowing rates in mature markets, which have a negligible chance of default. As the WACC is a forward-looking concept, regulators also sometimes consider future changes as given by forward yield curves on these same government bonds.

In principle, *real* bill and bond returns are most relevant because equity valuations are denominated in real terms (the underlying value of business assets will increase in nominal terms with inflation). A problem, however, with relying on historical assessments of real returns on bills and bonds for setting the RFR is that such returns have not been stable. This is because bills and bonds are denominated in nominal terms. The existence of inflation uncertainty therefore means that *ex-post* measures of real returns on bills and bonds do not necessarily reflect the *ex-ante* expectations of investors. For example, a lagged growth in inflation expectations before the 1980s and a lagged decline in inflation expectations from the 1980s seem to have been key factors in marked shifts in observed annual rates of return on bills and bonds.

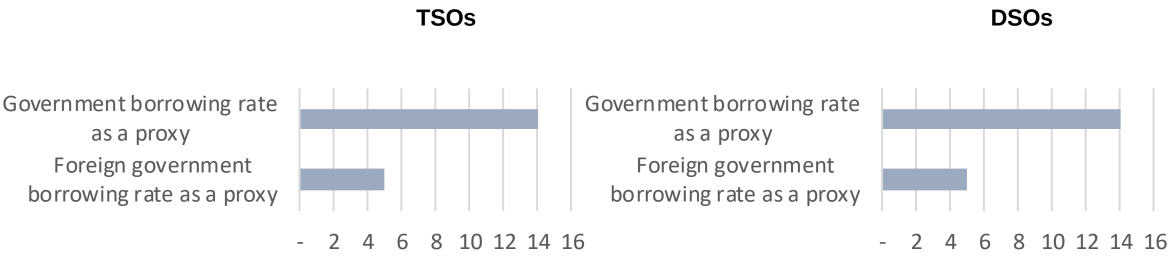
Consequently, as yields on nominal government bills and bonds are affected by inflation rate expectations, yields on inflation-adjusted bonds should provide a better insight into the RFR than yields on nominal bonds. However, inflation-adjusted bonds are a relatively new form of security which have been traded in some markets only since the 1980s.

Moreover, yields on inflation-adjusted bonds have progressively reduced over the last 20 years. Specifically, it appears that the real RFR has fallen markedly over this period.

Current estimates of the RFR would therefore be very low or even negative. A cautious forward estimate of the RFR might therefore recognise that negative yields are unlikely to be sustained, particularly as yields can vary significantly over relatively short periods of time. In general, the spot rate is the best measure of the current expectation of the future RFR given it incorporates, in theory, all evidence available at this time. However, some regulators and practitioners do not believe current spot rates can safely be used for a CAPM assessment, given that current yields are affected by what are expected to be ‘temporary’ actions of the monetary authorities, such as quantitative easing and other unconventional monetary policies.

In the ERRA sample, **the most common approach to determining the RFR in the calculation of the cost of debt and cost of equity is to use the government’s borrowing rate as a proxy** (14 TSOs and DSOS) (see Figure 51). The other approach is to use a foreign government’s borrowing rate as a proxy (five TSOs and DSOs). Austria and Oman fall into both of these categories; Austria uses the borrowing rate within the Euro area as a proxy. Austria, Estonia and Oman apply an inflation differential for the foreign proxy, and Hungary includes credit default swaps (CDS).

Figure 51 Approaches for determining the RFR in CoD and CoE calculations

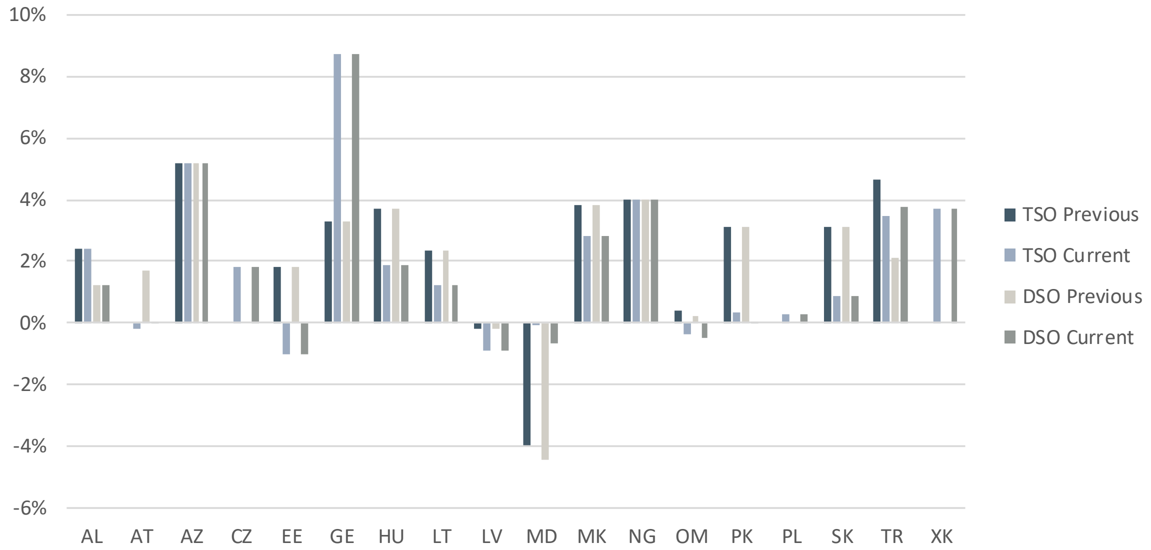


	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
TSO																				
RFR used in WACC?	✓	✓	x	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Government borrowing rate as a proxy	✓	✓			✓		✓		✓	✓		✓	✓	✓		✓	✓	✓	✓	✓
Foreign government borrowing rate as a proxy		✓				✓		✓			✓			✓						
DSO																				
RFR used in WACC?	✓	✓	x	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	x	✓	✓	✓	✓	✓
Government borrowing rate as a proxy	✓	✓			✓		✓		✓	✓		✓	✓	✓		✓	✓	✓	✓	✓
Foreign government borrowing rate as a proxy		✓				✓		✓			✓			✓						

Source: Survey questions 5.3 and 5.7. [†]See Footnote 2.

In Figure 52, we present the RFR used by ERRA TSOs and DSOs in the calculation of the WACC in the current and previous regulatory period. We deflate any reported nominal values using the average annual inflation rate for that period.

Figure 52 Real risk-free rate



Source: ECA calculations in Annex A1 based on survey question 5.9

4.4 Other revenue determinants

4.4.1 Technical losses

There are, essentially, two approaches to taking account of losses incurred in transporting electricity from the point of entry to the network to the point of exit:

1. One approach is to make these losses the responsibility of the network operators. The operators must make good the losses by purchasing electricity, and the **costs of losses form part of the allowed revenues**.

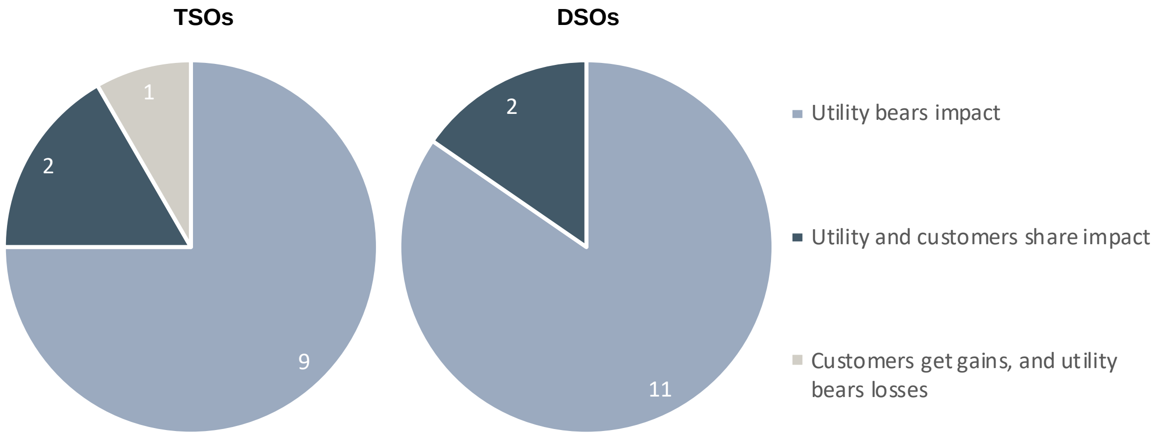
2. Alternatively, losses are not the responsibility of the network operators and, instead, are handled through the market using **loss adjustment factors**, which are taken into account to settle the energy bought and sold by suppliers and generators.

Where TSOs and DSOs have no responsibility for losses (case '2' above), they have no direct incentive to bring losses down to a reasonable or optimal level. It is therefore common to introduce other mechanisms to incentivise optimal investment and operating practices in order to ensure reasonable levels of losses. **If network operators do have responsibility to purchase losses, then they can be incentivised to reduce losses through the revenue control formulae. This is generally done by regulators determining a reasonable level of allowed technical losses** for each year in the regulatory period. Profits resulting from reducing losses below this cap could then be kept entirely by the utility or shared with customers based on a pre-set sharing factor;

similarly, unreasonable costs from exceeding the losses cap could either be borne by the utility or shared with customers.

In the ERRA sample, **regulators set a level of allowed losses for 14 TSOs and 16 DSOs**. Nine TSOs and 11 DSOs bear the impact of the deviation from allowed losses, ie any costs resulting from overshooting this cap are borne by the utility. For two TSOs and DSOs, the utility and customer share the impact. For Peru's TSO, this is shared through a pre-set sharing factor. For Albania's TSO and Czechia's DSO, this is shared through general adjustments during the next regulatory period. For Moldova's TSO, the customer gets the gains, while the utility bears the losses.

Figure 53 Incentive mechanisms for allowed technical losses

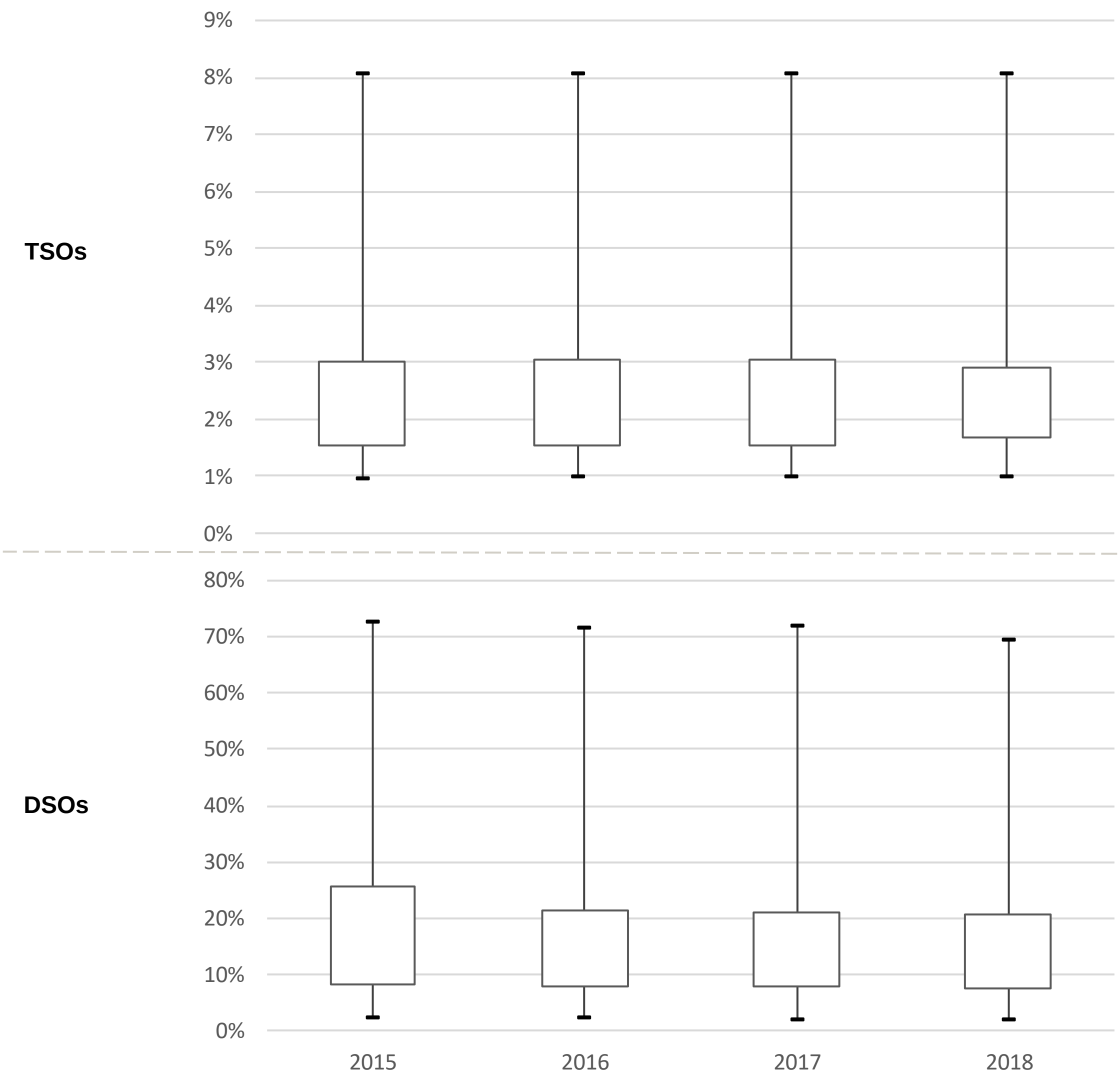


	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Regulator sets allowed losses?	✓	x	✓	✓	x	x	✓	✓	✓	x	✓	✓	✓	x	✓	✓	✓	✓	x	✓
Utility bears impact			✓	?			✓	✓	✓			✓	✓			✓	?	✓		✓
Utility and customers share impact	✓			?											✓		?			
Customers get gains, and utility bears losses				?							✓						?			
DSO																				
Regulator sets allowed losses?	✓	x	x	✓	✓	x	✓	✓	✓	x	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Utility bears impact	?			?			✓	✓	✓		✓	✓	✓		✓	✓	?	✓	✓	✓
Utility and customers share impact	?			?	✓									✓			?			

Source: Survey questions 6.1 and 6.3. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): In Bulgaria and Poland, and at Albania's TSO, we were unable to find out how the regulator shares gains and losses between utility and customer when the utility deviates from allowed losses.

In Figure 54, we present the allowed losses for TSOs and DSOs over the period 2015-2018 as box-and-whisker plots. Therefore, a negative value indicates that the TSO has outperformed expectations on losses.

Figure 54 Allowed losses



Source: Survey question 6.2

4.4.2 Quality of supply

Where incentives are introduced for utilities to increase the efficiency of their capital and operating expenditures (as with revenue or price cap regulation), this may also create incentives to delay projects or to otherwise minimise expenditure (such as maintenance) that may impact on the performance and quality of the networks. This can lead to immediate increases in profits while the impacts in terms of reduced service quality may only be felt later.

The typical (but not single) regulatory response to this is to **link allowed revenues and, therefore, profits, to measures of service quality**. Declining service quality results in lower allowed revenues. The regulated utility, therefore, has to balance the increased profits that come from delaying investments against the risk of falling service quality and the resulting revenue penalties.

Regulators typically monitor the reliability of supply, voltage quality, and customer services. In each of these areas, the regulator can define key performance indicators (KPIs) to monitor and report on regularly, and/or to use as a basis for performance or quality of supply regulation (incorporating penalties and/or rewards with respect to the achievement or non-achievement of targets). Some of the most common KPIs are defined in Table 16.

Table 16 KPIs for reliability of supply, voltage quality, and customer service

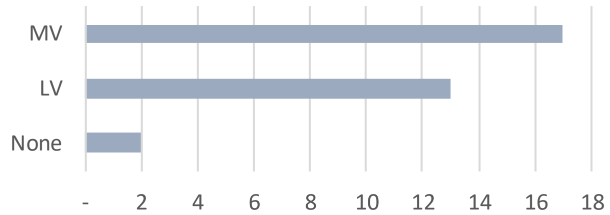
KPI	Description
Reliability of supply	
System Average Interruption Frequency Index (SAIFI)	▪ The average number of interruptions that each customer experiences in a given year (or over another time period). ▪ $SAIFI = \frac{Number\ of\ customer\ interruptions}{Number\ of\ customers}$
System Average Interruption Duration Index (SAIDI)	▪ The average duration of an interruption that each customer experiences in a given year (or over another time period). ▪ $SAIDI = \frac{Sum\ of\ customer\ interruption\ durations}{Number\ of\ customers}$
Customer Average Interruption Duration Index (CAIDI)	▪ The average duration of an interruption in a given year (or over another time period). ▪ $CAIFI = \frac{Sum\ of\ customer\ interruption\ durations}{Number\ of\ customers\ interruptions} = \frac{SAIDI}{SAIFI}$
Energy Not Supplied (ENS)	▪ The volume of energy to customers (MWh) that is lost due to faults or failures in the network each year.
Momentary Average Interruption Frequency Index (MAIFI)	▪ The average number of momentary interruptions experienced by each customer per year.
Outage rate	▪ The ratio of the amount of energy not supplied due to unplanned long interruptions to amount of available energy.
Voltage quality	
Flicker	▪ Visible change in the brightness of a lamp due to rapid voltage fluctuations in the power supply. ▪ Long- and short-term perceptibility values calculated using a flicker meter and statistical processes.
Frequency	▪ The rate at which current changes direction per second.
Harmonic voltage	▪ Harmonics are caused by certain types of loads which distort the voltage and current sinusoidal waveform in an AC system. As they can cause damage to electrical equipment and result in non-optimal operation of the electrical system and its equipment their effects are monitored and mitigated by using pulse converters and filters.
Mains signalling voltage	▪ Network operators use control signals at different frequencies to the supply frequency to manage system operations and for the control of certain loads. Because these signals can cause interference with core system operation, limits called 'mains signalling voltage limits' are defined to ensure no disturbances to network operation.
Sinusoidal form of the voltage power factor	▪ When the sinusoidal waveform of the current is in phase with the sinusoidal waveform of the voltage, real power is maximised, and reactive power is minimised. When the two waveforms are not in phase, leading or lagging power factors mean that more apparent power is flowing into the circuit and less real power. Power factors are usually

KPI	Description
	maintained at desired levels to avoid excessive losses due to this phenomenon.
Supply voltage variation	▪ Supply voltage variation describes changes in the voltage value and can be classified as short (voltage dips or sags) and long duration variations. ▪ Depending on the country there are standards as to the allowed voltage variation (+/-%) from the nominal voltage value.
Unbalance	▪ In an AC three phase system, voltage and current have three phases. Ideally, all three phases are of equal magnitude and their phase angles are equally apart (120 degrees). When these phases deviate in terms of either magnitude or phase from a perfect sinusoidal waveform, unbalance is observed. ▪ Unbalance is caused mostly by certain types of loads (non-linear loads). It results in inefficient system operation and can even cause equipment to trip.
Voltage dips	▪ Number of voltage dips. ▪ A voltage dip is momentary reduction in the root mean square voltage, usually resulting from a short circuit or turning on a heavy load in the network.
Voltage swells	▪ Number of voltage swells. ▪ A voltage swell is a momentary increase in the root mean square voltage, usually resulting from turning off a heavy load in the network.
Customer service	
Connection time	▪ Length of time for connecting new customers to the network.
Reconnection time	▪ Length of time for reconnecting a customer after outstanding debt is extinguished.
Restoration time	▪ Length of time to restore supply following a failure, a voltage disturbance, or a reduction in the quality of the voltage.
Complaints process	▪ Length of time to investigate and address customer queries and complaints
Supply interruption notice	▪ Whether adequate notice is given to customers for planned interruptions on the network.
Subscription time	▪ Length of time to register a new customer.
Metered data sharing time	▪ Length of time share metered data relevant to the further billing process with other companies
Meter replacement time	▪ Length of time to replace a dysfunctional meter
Metering node installation time	▪ Length of time to install a metering node.
Keeping to planned duration of interruption of supply	▪ Whether the utility sticks to the duration of the supply interruption specified *ex-ante* to customers.

Source: ECA

In the ERRA sample, **17 DSOs monitor medium voltage levels for supply and voltage reliability, 13 monitor low voltage, and two monitor neither** (see Figure 55).

Figure 55 Voltage levels monitored for supply and voltage reliability of DSOs

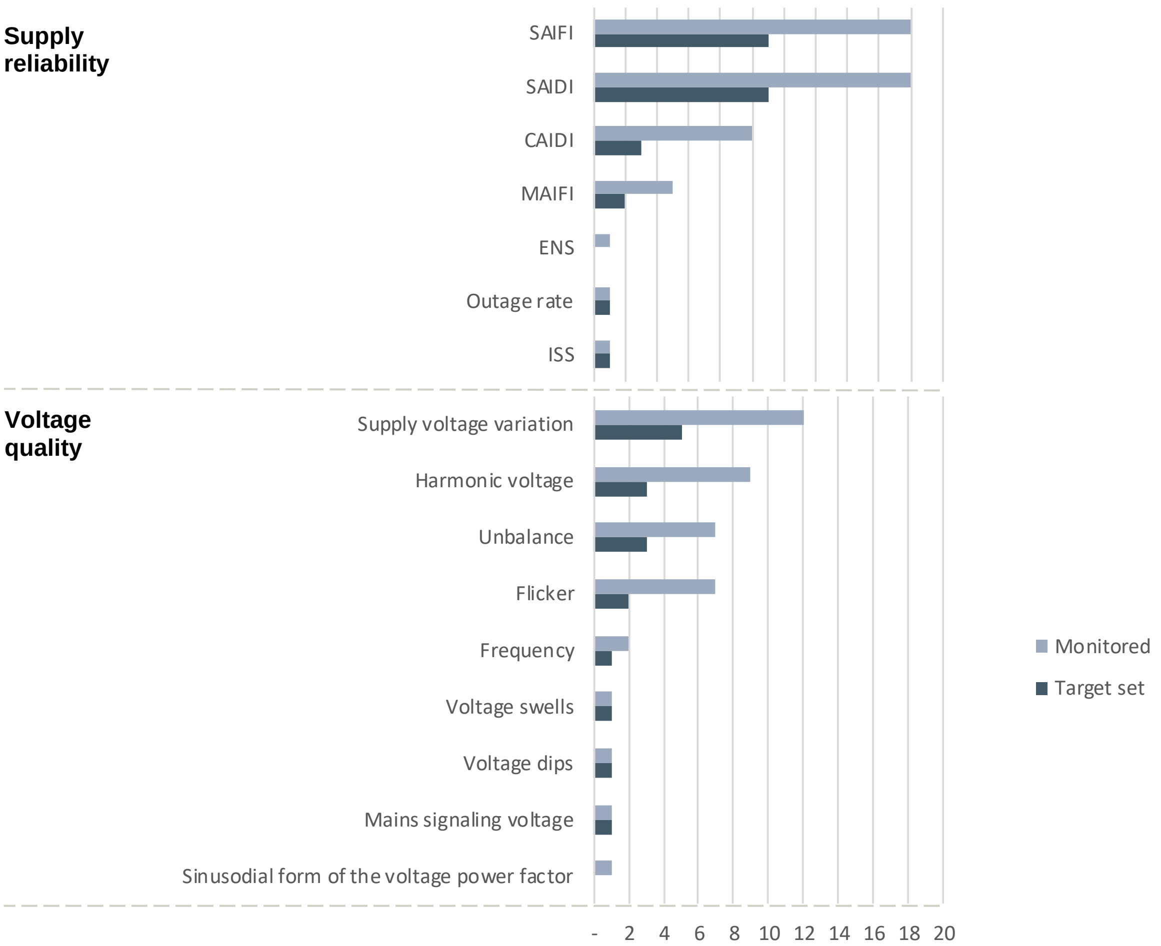


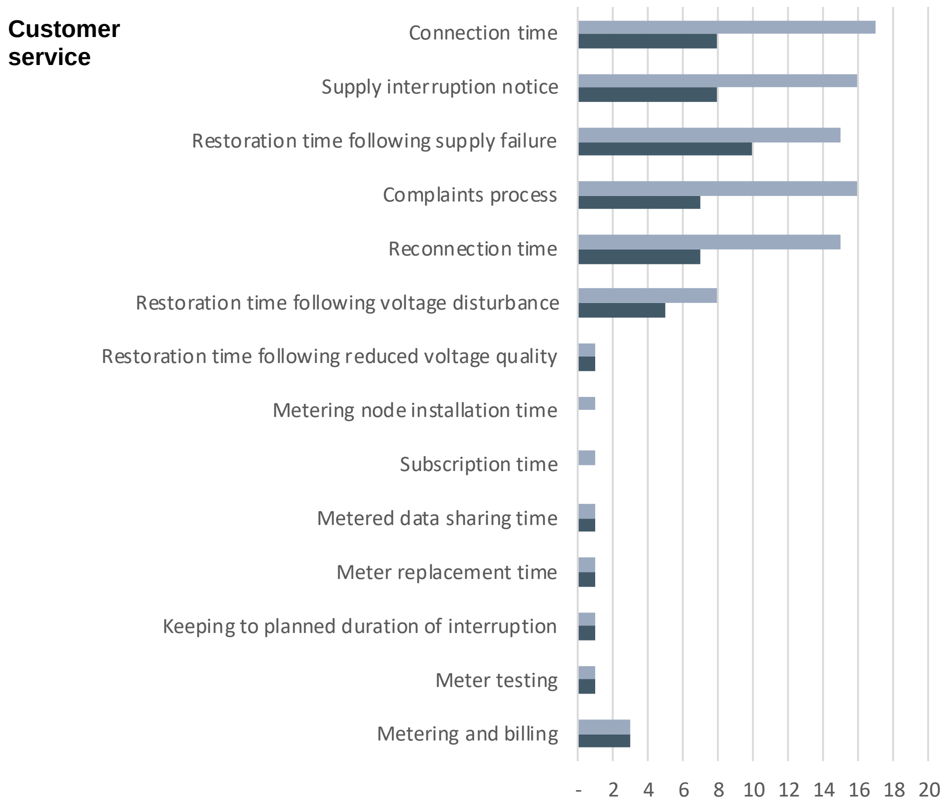
	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
MV	✓	✓		✓	✓		✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓
LV				✓	✓		✓	✓	✓	✓	✓	✓	✓			✓	✓	✓		✓
None			✓			✓														

Source: Survey question 7.1. †See Footnote 2.

To motivate good performance in these KPIs, regulators may set challenging annual targets. In Figure 56, we display the KPIs that are monitored and reported on regularly by DSOs beside the KPIs that have an annual target, or a target set over another specified period.

Figure 56 KPIs monitored and targets for DSOs



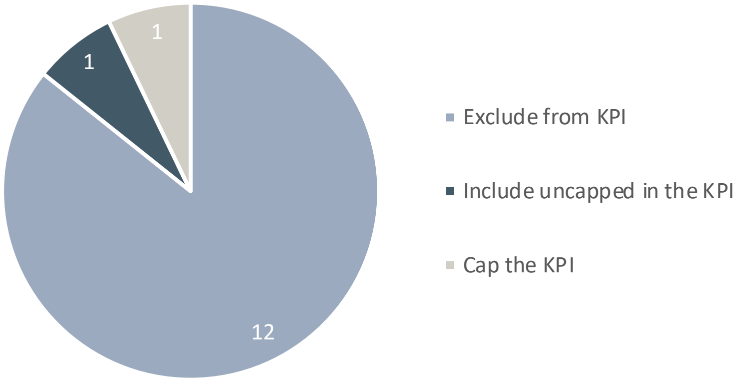


Source: Survey questions 7.2 to 7.5

Targets are best suited for customer-service KPIs, which are largely within the control of the regulated entity. Supply reliability and voltage quality under normal circumstances are also largely within the control of the network operator, but extreme events can lead to poor KPI outcomes in these areas. Some regulators control for this by removing these KPI outcomes during extreme events when comparing against the target, or by capping these KPI outcomes.

In the ERRA sample of DSOs, **of those setting targets for KPIs, the overwhelming majority exclude extreme events from their KPIs on supply reliability and voltage quality when comparing with their target** (12) (see Figure 57). Peru's DSO does not factor for extreme events when comparing these KPIs with their target, meaning they include the data uncapped in their KPIs. Estonia's DSO caps the KPI at a maximum value.

Figure 57 Approach for dealing with extreme events in KPI targets at DSOs

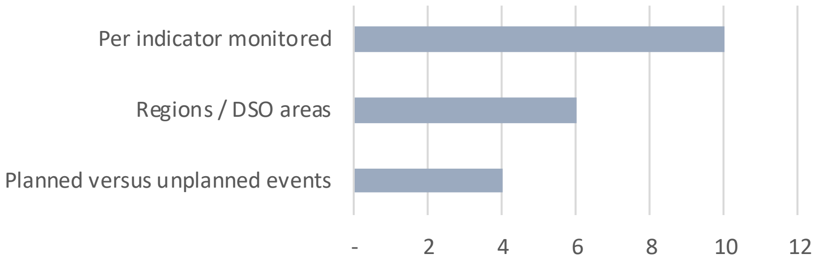


	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Targets for some KPIs?	✓	✓	x	✓	✓	✓	✓	✓	✓	x	✓	x	✓	✓	✓	✓	✓	✓	✓	x
Exclude from KPI	✓	✓		?	✓		✓	✓	✓		✓		✓	?		✓	✓	✓	✓	
Include uncapped in the KPI				?										?	✓					
Cap the KPI				?		✓								?						

Source: Survey question 7.6. †See Footnote 2. Unclear data (?): We understand that Bulgaria and Oman set targets for some KPIs, but we were unable to find out how they account for extreme events when comparing KPIs against targets.

In the ERRA sample of DSOs, for those setting targets, the majority specify different targets for each indicator monitored (ten) (see Figure 58). Six differentiate the target according to the region or DSO area, and four differentiate between planned and unplanned events in the target.

Figure 58 Approach for differentiating KPI targets at DSOs



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Targets for some KPIs?	✓	✓	x	✓	✓	✓	✓	✓	✓	x	✓	x	✓	✓	✓	✓	✓	✓	✓	x
Per indicator monitored		✓		?		✓		✓	✓		✓		✓	?	✓	✓	?	✓	✓	
Regions / DSO areas	✓			?	✓		✓				✓			?	✓	✓	?			
Planned versus		✓		?			✓				✓			?		✓	?			

	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
unplanned events																				

Source: Survey question 7.7. †See Footnote 2. Unclear data (?): We understand that Bulgaria, Oman and Poland set targets for some KPIs, but we were unable to find out whether or how they differentiate targets.

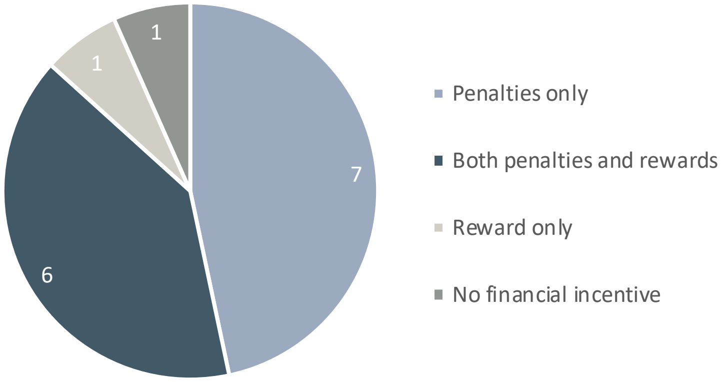
Once KPIs are established with measurable targets, incentive mechanisms tying performance against the targets with adjustments to the allowed revenues can motivate good outcomes. It also provides certainty to utilities on what the consequences are of failing to meet the required standards.

The regulator has the option to set rewards, penalties, or both, for the performance of KPIs against targets. Behavioural economics indicates that agents tend to exhibit loss aversion, meaning penalties are the best mechanism for incentivising achievement of targets. Furthermore, penalties are more justifiable than rewards; the target (in principle) reflects an outcome consistent with customer willingness to pay and allowed costs, and this is the level of performance that should be expected at the regulated tariff. With rewards, customers might consider they are paying twice for service (through both allowed revenues and rewards).

A further consideration is whether to allow the size of the penalty or reward to be tied to the scale of the deviation from the KPI, or whether simply to make the penalty or reward a fixed sum. The weakness of the latter approach is that, upon reaching the zone of penalty, the utility is no longer incentivised to reign in its poor performance. Likewise, upon reaching the zone of reward, the incentive to make further improvements is diminished; the utility may also consider maintaining the level of standards so that improvements in the next period are easier. A weakness of the former approach is that the utility is placed at financial risk if they adversely deviate too far from their target and the penalty grows too large. Similarly, the reward may reach a level that results in unjustifiable reward payments from customers. Some regulators overcome this by setting relative rewards or penalties that are capped at a maximum value.

In the ERRA sample of DSOs, **the most common approach is to only set penalties** (seven) (see Figure 59) followed by setting both penalties and rewards (six). Only Turkey sets rewards but not penalties, and only Austria does not set financial incentives for achieving KPI targets. In Lithuania, both penalties are rewards apply to the four DSOs with fewer than 100,000 clients, but only penalties apply to one DSO with more than 100,000 clients.

Figure 59 Financial incentives for achieving KPI targets at DSOs

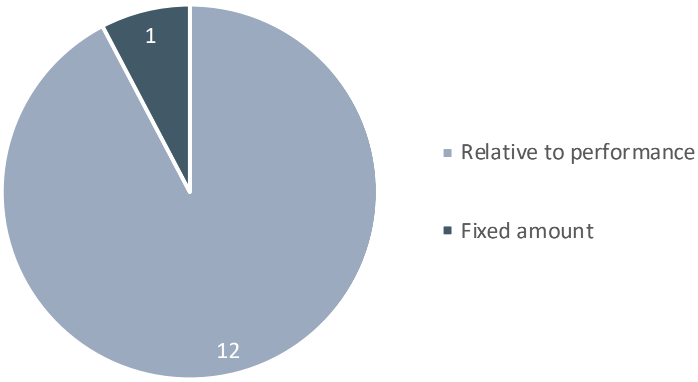


	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Targets for some KPIs?	✓	✓	x	✓	✓	✓	✓	✓	✓	x	✓	x	✓	✓	✓	✓	✓	✓	✓	x
Penalties only	✓			?		✓					✓		✓			✓	✓	✓		
Both penalties and rewards				?	✓		✓	✓	✓					✓	✓					
Reward only				?															✓	
No financial incentive		✓		?																

Source: Survey question 7.8. †See Footnote 2. Unclear data (?): We understand that Bulgaria set targets for some KPIs, but we were unable to find out what financial incentives they use to ensure the targets are met.

For those setting a financial incentive for KPI targets, **the majority (12) scale the penalty or reward relative to performance** (see Figure 61). Only Albania gives a fixed penalty.

Figure 60 Scaling of financial incentives for achieving KPI targets at DSOs

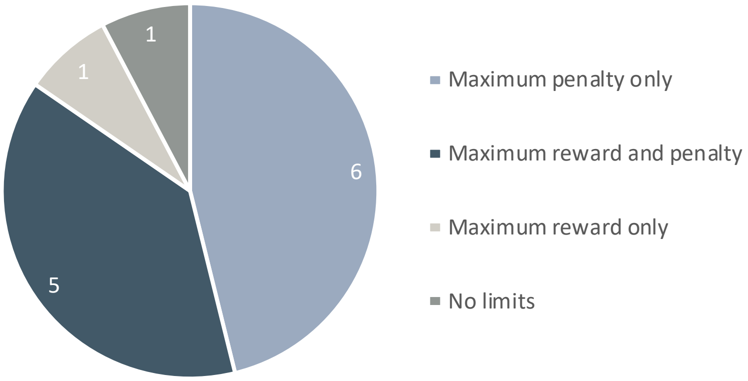


	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
Targets with financial incentive for some KPIs?	✓	x	x	?	✓	✓	✓	✓	✓	x	✓	x	✓	✓	✓	✓	✓	✓	✓	x
Relative to performance				?	✓	✓	✓	✓	✓		✓		✓	✓	✓	✓	?	✓	✓	
Fixed amount	✓			?													?			

Source: Survey question 7.9. †See Footnote 2. Unclear data (?): Bulgaria sets some KPI targets, but we were unable to find out what financial incentives they use. We understand that Poland sets penalties to incentivise the achievement of KPIs, but we were unable to find out whether these are fixed or scaled.

For those scaling the incentive in line with performance, six set a cap on both the reward and penalty, five set a cap on the penalty only, and Turkey sets a cap on the reward only (see Figure 61). Nigeria sets no limit on its penalty.

Figure 61 Limits on scaled financial incentives for achieving KPI targets at DSOs



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK[†]
Targets for some KPIs with scaled financial incentive?	x	x	x	?	✓	✓	✓	✓	✓	x	✓	x	✓	✓	✓	✓	?	✓	✓	x
Maximum penalty only	✓			?		✓			✓		✓					✓	?	✓		
Maximum reward and penalty				?	✓		✓	✓						✓	✓		?			
Maximum reward only				?													?		✓	
No limits				?									✓				?			

Source: Survey question 7.10. [†]See Footnote 2. Unclear data (?): We understand that Bulgaria set targets for some KPIs, but we were unable to find out what financial incentives they use to ensure the targets are met. We understand that Poland sets penalties to incentivise the achievement of KPIs, but we were unable to find out whether these are fixed or scaled.

5 Revenue adjustments

In our discussion on the length of the regulatory period (see Section 3.2), we highlighted that there is a trade-off between small and large gaps between regulatory reviews. Less frequent reviews reduce the burden on the regulator and utility to complete work-intensive reviews. However, a long regulatory period creates a greater likelihood for costs and revenues to diverge, given that revenues are based on forecasts or actual costs at the time of the review. **This can lead to financial risk for the utility if costs exceed allowed revenues, or an unreasonably high tariff for customers if revenues exceed costs for an extended period**.

This can be addressed by allowing for certain automatic adjustments withing the regulatory period, or to adjust the revenues determined at the next regulatory review to compensate for deviations between revenues and costs in the previous regulatory period.

In the preceding sections, we have discussed such adjustments in the context of opex and capex determination:

- **Opex (Section 4.1):** The regulator may adjust for differences between allowed and actual opex. The regulator may apply further adjustments to compensate in the case of a time delay in these adjustments, considering time inconsistency of preferences (ie discounting) and inflation.

- **Capex (Section 4.2):** The regulator may adjust for differences between *ex-ante* approved capex and actual capex, including over- and under-spends and deferrals. As with capex, the regulator may apply further adjustments to compensate in the case of a time delay in these adjustments. In the case of capex deferral, the regulator could adjust the present value of the investment by discounting more heavily, given that the commissioning year will be later.

In addition, the regulator may automatically adjust for:

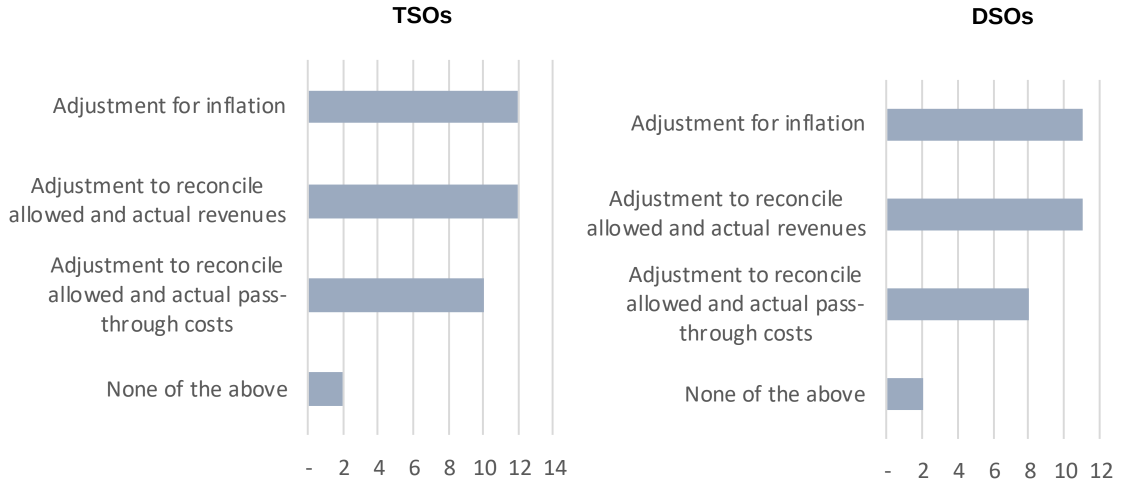
- the difference between allowed/actual revenues;

- the difference between allowed/actual pass-through costs; and

- inflation.

In the ERRA sample, **12 TSOs and 11 DSOs adjust for inflation. Twelve TSOs and 11 DSOs adjust to reconcile the difference between allowed and actual revenues. Only ten TSOs and eight DSOs adjust to reconcile the difference between allowed and actual pass-through costs**.

Figure 62 Revenue adjustments allowed by the regulator



	AL	AT	AZ	BG	CZ	EE	GE	HU	LT	LV	MD	MK	NG	OM	PE	PK	PL	SK	TR	XK†
TSO																				
Adjustment for inflation		✓	✓	✓	✓		✓	✓	✓				✓	✓		✓	?		✓	✓
To reconcile allowed and actual revenues				✓	✓		✓	✓	✓		✓	✓		✓	✓		?	✓	✓	✓
To reconcile allowed and actual pass-through costs	✓	✓					✓	✓	✓					✓		✓	?	✓	✓	✓
None of the above						✓				✓							?			
DSO																				
Adjustment for inflation		✓	✓	✓	✓		✓	✓	✓				✓	✓	?		?		✓	✓
To reconcile allowed and actual revenues				✓	✓		✓	✓	✓		✓	✓		✓	?		?	✓	✓	✓
To reconcile allowed and actual pass-through costs	✓	✓						✓	✓						?	✓	?	✓	✓	✓
None of the above						✓				✓					?		?			

Source: Survey question 6.4. Red marks indicate a divergence between the TSO and DSO method. †See Footnote 2. Unclear data (?): We were unable to determine the approach Poland applies to its TSO or DSO and the approach Peru applies to its DSO.

6 Conclusions

The present study, based on the ERRA survey issued to the relevant MOs, provides a comparative analysis of the methodological approaches adopted by the regulators in the relevant countries. As demonstrated in the preceding sections of the report, there is **considerable variation among regulatory regimes. This is to be expected given the various factors that impact on methodological choices**, including:

- Historical circumstances in the various countries eg the form of ownership, legacy obligations and policy preferences.
- Geography and sector characteristics, such as electricity consumption patterns.
- The macroeconomic framework and business cycle, which affect among other things interest rates and input costs.
- Growth in demand, which in turn depends on economic circumstances, the maturity of the sector, the structure of downstream sectors and the composition of network users.
- Social and economic objectives regarding affordability and price stability.
- National legal or other constraints such as the choice of funding models and target returns on equity, for example, for state owned companies.

Notwithstanding the country differences, **there do seem to be some general tendencies or framework elements across all or a majority of the MOs** including:

- Increasing independence of the regulatory authorities and transparency of the applicable regulatory methodologies.
- The predominance of price/revenue caps and/or the inclusion of incentive-based arrangements in setting the allowed revenues.
- The adoption of multi-year regulatory periods (mostly between three to five years), which is consistent with the setting of price or revenue caps.
- The overwhelming use of a 'building blocks methodology' to determining revenue requirements.
- The predominate reliance on bottom-up assessments of opex.
- The setting of capex in most cases in advance, with attempts at assessing both the technical justification for proposed investments and the reasonableness of the level of expenditure.
- The use of the 'CAPM' model in estimating reasonable equity returns and therefore an allowed rate of return, and the reliance on notional gearing ratios

to reflect what is considered a reasonable or optimal capital structure for these regulated businesses.

- The establishment of quality metrics for electricity distributors, which are increasingly tied to incentive payments (rewards or penalties or both) to ensure that cost minimisation is not achieved at the expense of the quality of service.

Based on the comparative analysis, and also drawing on regulatory experience more generally, **we do identify areas that could be considered by MOs as their regimes continue to evolve**:

- **Regulatory independence and rigour in reviewing cost submissions by the regulated entities can be further reinforced** by ensuring that regulatory duties and powers are sufficiently defined to ensure greater certainty, transparency and accountability in the exercise of the necessary judgement involved with tariff regulation. Such measures include obliging the regulated businesses to consult with interested parties, seeking explanations and an evidence basis for any forecast of costs, revenues and outputs, and the regulator publishing its decisions, including the rationale and analysis underpinning them.

- **The sense-checking of bottom-up cost assessments of operating expenditure by applying additional or alternative assessment procedures** to ensure the neutral treatment of opex and capex, avoiding possible biases for capex over opex, and allowing for the efficient delivery of services (including substitution possibilities among opex categories or between opex and capex).

- **Examining the incentive properties of the current regulatory regimes and ensuring that incentives are neutral across cost categories and time**. For example, the current common practice of setting revenue or price caps without any adjustments or pre-set sharing factors, discourages savings late in the regulatory period. There are various mechanisms for addressing this including the application of 'efficiency benefit sharing mechanisms'.

- **Factoring in efficiency improvements to account for savings that the regulated TSOs and DSOs can reasonably be expected to achieve in the future owing to productivity increases over time**. There is currently relatively limited use made of efficiency factors among MOs, either at the level of the tariff or revenue control, or in setting cost allowances.

- **Subjecting material capex proposals to greater scrutiny, both to ensure that the proposed investments are needed (and are those that best meet objectives compared to alternatives), and that they are delivered at the lowest possible cost**. Currently, the focus seems to be on technical necessity and unit costs. Arguably, all substantive investment projects or programmes of the electricity network businesses should be underpinned by economic justification and a demonstration that the forecast expenditure is expected to be the lowest cost option in the long-run relative to other feasible options. More detailed consideration could also be given to the different cost drivers of expenditure by category (refurbishment, extension, metering/connection assets, etc).

- **Permitting the regulated network businesses to gross-up asset values for financing costs incurred during construction when assets are rolled into the RAB upon commissioning.** In the absence of this (as seems to be the most common, although not universal, practice among the MOs), the financial capital maintenance principle (which requires that the present value of the allowed revenue stream equals the present value of the expenditure stream of the regulated networks) is violated. This would be in breach of a fundamental regulatory duty of ensuring that all reasonable costs (including a 'fair' return are recovered) and could create financing difficulties for the businesses thereby jeopardising needed investment.