Status Review of Main Criteria for Allowed Revenue
Determination
for transmission, distribution and regulated supply of electricity and gas

December 2013
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EXECUTIVE SUMMARY

Energy prices and network tariffs are crucial for customers both in terms of their level and the services included. The treatment of certain elements for their calculation, such as network and commercial losses, bad debts, new investments, as well the level of return guaranteed to network operators and/or suppliers has direct influence on charges’ level. In this context also the treatment of commodity prices i.e. calculation of public suppliers’ prices is of crucial interest.

The present report assesses the currently implemented elements of regulated network tariffs and end-user energy prices as well as the criteria for their calculation in the Energy Community. The analysis investigates whether the regulatory authorities of the Energy Community follow the same principles and criteria when regulating tariffs and prices but does not evaluate the appropriateness of the applied mechanisms.

The report covers Albania, Bosnia and Herzegovina, Croatia, Former Yugoslav Republic of Macedonia, Georgia, Kosovo*, Moldova, Montenegro, Serbia, Turkey and Ukraine.

The assessment shows that regulation of energy industry follows similar principles and criteria for determining network tariffs and, where applicable, end-user prices in all analysed markets.
INTRODUCTION

The Energy Community

The Energy Community comprises Albania, Bosnia and Herzegovina, the former Yugoslav Republic of Macedonia, Kosovo\(^2\), Moldova, Montenegro, Serbia and Ukraine. Armenia, Georgia, Turkey and Norway are Observer Countries.

The Energy Community Regulatory Board (ECRB) operates based on Article 58 of the Energy Community Treaty. As an institution of the Energy Community the ECRB advises the Energy Community Ministerial Council and Permanent High Level Group on details of statutory, technical and regulatory rules and should make recommendations in the case of cross-border disputes between regulators.

Background

Energy prices and network tariffs are crucial for customers both in terms of their level and the services included. The treatment of certain elements for their calculation, such as network and commercial losses, bad debts, new investments, as well the level of return guaranteed to network operators and/or suppliers has direct influence on charges' level. In this context also the treatment of commodity prices i.e. calculation of public suppliers' prices is of crucial interest.

The Energy Community acquis communautaire on electricity and gas\(^3\) requires regulatory authorities to ensure that transmission and distribution tariffs are transparent, cost-reflective\(^4\) and allow for necessary investments in networks\(^5\). The Third Energy Package additionally requires regulated tariffs or the methodologies for their calculation to ensure that transmission and distribution network operators are granted appropriate incentives, over both the short and long

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1. [www.energy-community.org](http://www.energy-community.org).
2. Throughout this document the symbol * refers to the following statement: 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.
5. Art.23(2) of Electricity Directive and Art.25(2) of Gas Directive.
term, to increase efficiencies, foster market integration and security of supply and support the related research activities⁶.

Scope

The present report assesses the currently implemented elements of regulated network tariffs and end-user energy prices as well as the criteria for their calculation. The analysis investigates whether the regulatory authorities of the Energy Community follow the same principles and criteria when regulating tariffs and prices but does not evaluate the appropriateness of the applied mechanisms.

With the exception of available information on network losses and rates of return, the assessment neither provides figures on allowed revenues and their elements nor on levels of network tariffs and energy prices. The analysis of actual cost-reflectivity of tariffs and prices would require in-depth investigation of specific national circumstances—market development, legislation and regulation.

The report covers Albania, Bosnia and Herzegovina, Croatia, Former Yugoslav Republic of Macedonia, Georgia, Kosovo⁎, Moldova, Montenegro, Serbia, Turkey and Ukraine. Where results for Bosnia and Herzegovina differ for the Federation of Bosnia and Herzegovina (FBIH), Republika Srpska (RS) and Brcko District of BIH, they are displayed separately in this survey.

Methodology

Data and analyses provided in the present report is exclusively based on information provided by the regulatory authorities of the analyzed markets. The questionnaire used for data collection is displayed in the Appendix to this report.

Data displayed for Georgia and Turkey is not complete and/or clarified in all chapters and only available to the extent provided by the related regulatory authorities.

FINDINGS - ELECTRICITY

Electricity transmission and distribution

1. Type of regulation

Similar to product prices in other regulated network industries, electricity transmission and distribution tariffs can be determined by using different types of price control mechanisms:

- **Cost plus (or rate-of-return) regulation**, where tariffs are set in a way to cover the system operator’s justified costs and include a rate of return i.e. a return on the capital invested;
- **Revenue or price cap regulation**, where revenues/prices are set in advance for a fixed period of several years ("regulatory period") allowing system operators to keep cost savings they are able to acquire during this period due to, e.g. increase of efficiency in system operation. Typically, yearly tariffs resulting from cap regulation only vary based on the level of inflation corrected by a predetermined percentage rate of efficiency growth\(^7\);
- **Other mechanisms**, such as yardstick regulation or performance based regulation; these models are, however, less widely spread compared to the previously mentioned mechanisms.

In the analyzed markets cost plus, price cap and revenue cap regulation are implemented. Cost plus regulation is normally performed on yearly basis\(^8\), while in the case of incentive based regulation the revenues or prices are caped for different periods, namely 3 or 5 years. The figure below provides an overview on the applied tariff regulation models per country.

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\(^7\) CPI-X regulation involves setting a price-path (price-cap regulation) for a utility, allowing for changes in inflation (the CPI factor) and expected efficiency improvements (the “X” factor: These efficiency improvements are separate from the economy-wide efficiency improvements already reflected in the change in the CPI). The “X” factor may incorporate other aspects in addition to the expected improvement in efficiency, such as rewards for improvements in output quality, service levels or demand management actions. CPI-X regulation may also be applied to total required revenue under revenue-cap regulation (Independent Pricing and Regulatory Tribunal (Dennis Mahoney, Cato Jorgensen, Thomas Clay), Incentives for cost saving in CPI-X regimes, July 2011).

\(^8\) This however does not mean that tariffs are necessarily changed every year, but that the calculation base is one year. Tariffs are changed on the request of regulated company or when regulator concludes that basic parameters for allowed revenue and tariff calculation have been changed.
Specific rules apply for electricity distribution in Georgia and Ukraine:

- in Georgia, long term tariffs\(^9\) have been established based on a memorandum of understanding between the state and investors.
- In Ukraine a cost plus method with some elements of incentive based regulation are implemented for 5 electricity distribution companies, privatized in 2001\(^10\). More in detail, for the first 7 years after the adoption of the methodology (2001 to 2008) for these 5 companies tariff calculation was based on a single rate of return on assets of 17\% after tax. For the next five years (period 2008 to 2013) the rate of return is determined by NERC, but cannot be lower than 11\%. At present, the rate of return is 15\%. In order to encourage cost cutting the methodology envisages fixing the level of operating costs (at the beginning of application of the methodology for a term not exceeding 7 years), adjusted to reflecting changes in the producers price index and tariff adjustment when changing consumption volumes are more than 5\% of the those used in the approved tariff\(^11\). It has to be noted, though, that – based on the information available - the applied adjustment parameters seem to rather entail correction to external factors than a real cost cutting incentive.

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\(^9\) Details on the duration and content of this Memorandum have not been provided by the Georgian regulator.

\(^10\) For other distribution companies cost plus methodology is used.

\(^11\) Incentive based regulation does not refer to CPI-X methodology, as explained above.
2. **Allowed revenue and accounting guidelines**

For all types of tariff regulation **allowed revenue need to be determined**, i.e. costs allowed to be recovered via the network tariff. Eligible costs include justified and efficient operation and maintenance costs and the capital costs (depreciation and return on assets). Allowed revenues additionally also include the compensation of network losses as well as a correction factor addressing variations between the forecast and actual values.

In order to facilitate the process of allowed revenue calculation, some regulatory authorities require regulated companies to prepare and submit separate regulated accounts that - to a certain extent - differ from national statutory accounting standards. Such “**regulatory accounting rules**” (guidelines) should not create an additional burden for regulated companies but help them in understanding the process of regulation and increase transparency.

Among the analyzed electricity markets regulatory authorities define separate regulatory accounting guidelines only in the entities of Bosnia and Herzegovina for distribution and Albania, Croatia, Kosovo*, Moldova and Turkey for both transmission and distribution. In Montenegro accounting rules for tariff regulation will be applicable to all regulated energy undertakings as of 1 January 2014.

3. **Operating and maintenance costs**

Operating and maintenance costs (O&M costs) allow regulated companies to provide and maintain the adequate service level. Regulatory authorities recognize operating and maintenance costs in the allowed revenue but have to differentiate between justified and non-justified costs in order to avoid excessive and unnecessary costs being included in tariffs.

The assessment hereinafter analyses whether regulators apply **criteria for recognition of operational expenditures** in the allowed revenue defining which costs are considered justified/non-justified, predefining some costs as controllable and non-controllable and/or predetermining limits for certain costs.

- The regulatory authorities of Bosnia and Herzegovina, Croatia, Georgia, Kosovo* and Turkey include all **operating and maintenance costs** from statutory accounting in the allowed revenue for electricity transmission and distribution.

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12 In Croatia a *Decision on the Method and Procedure for Keeping Separate Accounting of Energy Undertakings*, adopted by the regulatory authority (Official Gazette No. 103/03) exists. In Moldova a *Regulation on accounting system at the regulated electro energetic companies*, approved by the decision of the Administrative board of the National Agency of Energy Regulation No. 78 of 29.12.2002 exist. In Kosovo* these rules are part of TSO/NO and DSO Pricing Rules.

13 Non-controllable costs, if recognized as such, are normally automatically included in the allowed revenue.

14 The exception is distribution in BIH entity Republika Srpska- the regulator does not automatically include all O&M costs from statutory accounting.
On the other side, regulators in Albania, Moldova, FYR of Macedonia, Montenegro, Serbia and Ukraine define certain categories of O&M costs as **justified or non-justified** and consider all O&M costs **controllable**. However, an explicit list of non-justified costs only exists in Moldova, Montenegro and Ukraine and includes fines/penalties system operator have to pay to other authorities, sponsorships, doubtful debt\(^{15}\), costs of network connections\(^{16}\) etc.

In FYR of Macedonia the regulatory authority defines **limits for some costs categories**: for example, maintenance costs may only amount to 25% of annual depreciation costs and gross salaries per employee are only recognized to the extent not 40% higher than average gross salaries in the country.

A graphical overview of the implemented approaches for recognition of operating and maintenance costs in the allowed revenue is presented in Figure 2.

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\(^{15}\) A **doubtful debt** is an account receivable that might become a bad debt at some point in the future.

\(^{16}\) Costs of network connections are to be covered by separate connection charge.
efficient costs is reflected in the X factor. The X factor applies for a given number of years (the regulatory period) and determines the annual change in prices in such a way that prices move in line with the anticipated efficiency improvements. Through the X factor, consumers directly participate in the expected cost reductions in the form of lower price. On the other hand, the company will also benefit as long as it manages to reduce costs in excess of the X factor. The residual cost savings can then be retained in the form of higher profits."\(^{17}\)

As explained earlier, incentive base regulation for electricity transmission is only applied in Albania, FYR of Macedonia\(^ {18}\), Kosovo*, Moldova, Montenegro and Turkey. The following efficiency factors currently apply:

For transmission:
- 0% in Albania and Turkey
- 4% in Kosovo*
- 2% in Moldova and
- 0.5 of the consumer price index (CPI) in Montenegro

For distribution:
- 0% by the end of 2014 in Albania, set by the regulatory statement that is a part of the privatization agreement,
- 5% as of 2015 in Kosovo*
- 2% sector based in Moldova,
- 0.5 of the CPI, sector based, in Montenegro
- Individually based for 21 DSOs in Turkey and
- 0% for five companies where incentive based regulation is applied in Ukraine\(^ {19}\) (as mentioned above, operating costs are fixed for a certain period, but adjusted only based on inflation or related indices. During 2013 the regulator carried out activities in order to implement incentive tariff regulation for electricity DSOs. The overall performance indicator was used to control operating costs. For the first regulatory period (three years), this factor is set at 1%. From the second regulatory period individual performance indicator will be introduced, which will be calculated on the basis of benchmarking analysis (DEA and parametric methods)).

However, the methodologies for X factor determination still do not follow academically recognized benchmarking models, such as parametric and non-parametric tests, but the

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\(^{17}\) Efficiency factor's determination (X factor). Issue paper of ERRA Tariff/Pricing Committee, prepared by KEMA International B.V. in August 2006, please see more on X Factor determination on http://www.erranet.org/Library/ERRA_Issue_Papers#2.

\(^{18}\) Revenue cap type of regulation applied in FYR of Macedonia is based on setting a 3-years- revenue stream allowing increase in revenues coming from inflation rate and smoothing factor i.e. factor that distributes differences between planned revenues of a company and those approved by the regulator over the regulatory period. Increase in efficiency is currently not envisaged.

\(^{19}\) See chapter 1.
individually developed procedures of the relevant regulatory authorities. In Kosovo*, for example, the regulator uses productivity standards: for measuring potential efficiency improvements the number of employees per 100km of network is used as reference standard. Furthermore, when defining the efficiency factor, the regulator compares equipment used in Kosovo and other similar electricity systems but also takes into account similarities in tariff proceedings. In Montenegro the efficiency factor is set on the basis of comparison to efficiency factors applied by regulators of other countries, for companies with the same or similar performances. In Moldova the regulator takes into consideration efficiency improvements in the previous periods as well as the investments contributing to efficiency increase.

In addition to regular operating and maintenance costs,

- the regulatory authorities of Albania, FYR of Macedonia, Montenegro and Serbia recognize costs related to reactive power as part of electricity transmission system operators’ revenues. These costs are normally not displayed as separate category, but constitute a part of other costs, such as ancillary services, losses etc. However, the majority of regulatory authorities (Bosnia and Herzegovina, Croatia, Georgia, Kosovo* and Moldova) state that TSOs did not have costs related to reactive energy but consider revenues earned from reactive energy a part of generators’ income, i.e. these revenues have to be transferred to generators.

- For electricity distribution the costs of reactive power are included in the allowed revenue only in Bosnia and Herzegovina-Republika Srpska and FYR of Macedonia. In Albania, realized costs of reactive power from the previous year are deducted from the DSO’s allowed revenue of the current year. Nevertheless, an explicit tariff for reactive energy exists in all analyzed markets for system users that can register consumption of reactive energy.

The regulators of Bosnia and Herzegovina, FYR of Macedonia and Serbia also cover cost of reserves in the DSOs’ allowed revenue.

4. Return on assets

In order to recognize owner’s investment in the regulated company, allowed revenues includes return on assets. Return on assets is measured by multiplying the rate of return with the value of the regulatory asset base. The regulatory asset base (RAB) aggregates net asset values of fixed assets and sometimes current assets (also referred to as “working capital”), excluding capital contributions and sometimes also assets under construction.

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20 Reactive energy is normally one of the tariff elements for electricity transmission and/or distribution.
21 Tariff for reactive power is 15% of tariff for active energy; however there is no realistic calculation of planned reactive energy and the revenue earned from it is treated as deducted revenue (please see Chapter 8). As of 2014 this practice will be changed.
22 Assets not yet commissioned, i.e. not yet in use.
Asset valuation is an important element of RAB determination. Some regulatory authorities therefore prefer using their own asset valuation methodology. In any case all regulators have a discretionary right to define and decide which assets belong to the regulated business and, to avoid sunk investments\(^{23}\), which investments are justified.

The survey related to **RAB structures and asset valuation** is presented below. It has to be highlighted that the process of allowed revenue determination in Ukraine does not apply the concept of RAB related calculation of return. The allowed revenue for the majority of companies is calculated so to include all reasonable operating costs, depreciation, return on investments and income tax. For 5 companies (privatized in 2001) the company purchase price (resulting from the privatization process) is used as the rate base for revenue calculation together with investment and depreciation. The new methodology of incentive based regulation will introduce RAB concept. Therefore, the information on Ukraine in this and the following chapter will be only selective to the extent available. When providing information on RAB, this consequently does not include Ukraine.

\(^{23}\) Investments that will not allow recovering of capital invested, because e.g. relevant asset will be underused or not used at all.

### Table 1 Role of regulators in evaluating electricity transmission and distribution assets

<table>
<thead>
<tr>
<th>Country</th>
<th>Has the regulator right to re-evaluate assets if deems necessary?</th>
<th>Have assets been re-evaluated in the process of tariff regulation?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>yes</td>
<td>No</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>no for transmission/ yes for distribution</td>
<td>no</td>
</tr>
<tr>
<td>Croatia</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Georgia</td>
<td>yes</td>
<td>no for transmission/ yes for distribution</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Moldova</td>
<td>no</td>
<td>yes</td>
</tr>
<tr>
<td>Montenegro</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Serbia</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Turkey</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Ukraine</td>
<td>no</td>
<td>yes, but the reason was not related to regulatory process</td>
</tr>
</tbody>
</table>
In Albania, Georgia, Kosovo*, Montenegro and Turkey for transmission and distribution and Bosnia and Herzegovina only for distribution, the regulatory authorities have a legal right to re-evaluate assets of regulated companies. In Kosovo*, Moldova and Turkey the regulator corrects asset values only to the consumer price index (CPI). In Montenegro the regulator may require an independent body i.e. auditor to re-evaluate assets if the value presented by transmission or distribution companies is doubtful; however, the regulator so far has not exercised this power.

In all investigated markets the regulatory authorities approve investment plans ex-ante and monitor their implementation. The realization of investment plans influences the value of the RAB only to the extent the allowed revenue includes some investments in advance i.e. before commission of assets, which is the case only in Montenegro. More in detail, in Montenegro the assets under construction are included in the RAB as a tool for incentivizing investments: for the first year of the 3 year regulatory period the costs related to construction in progress at the end of the previous year are included, for the second year the sum of construction in progress costs for the previous two years and for the third year the sum of construction in progress costs for the previous three years. However, if during a year an investment is realized with a value less than 50% of the value approved for that year, the regulator excludes the total value of the relevant investment as well as relevant depreciation from the RAB until the asset is put in operation. If an investment, whose implementation is planned for the period of three or more years, is realized during the first two years by less than 50% of the plan for the relevant period, the total investment is excluded from the basis for calculation of depreciation and return until put into operation.

Another very important element of RAB calculation are capital contributions, i.e. grants from e.g. the government or an international institution and direct payments by asset users, in case of networks typically connection assets. Normally the assets financed from such contributions are excluded from the RAB, in order to avoid return on assets that are not the result of the regulated company’s investment. In some cases however, depreciation of these assets is allowed with a view to enable replacing of the assets in the future.

In all analyzed markets capital contributions are excluded from the RAB by the regulators. However the depreciation of capital contributions is included in the allowed revenue for electricity transmission and distribution in the majority of analyzed markets. For details, please see the figure below.

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24 In Ukraine the regulator considers investment plans of the company after prior approval of the relevant ministry. The regulator may decide not to include into tariff some items of investment plan approved by the ministry.
Other elements considered for calculating the RAB are intangible assets and working capital. **Intangible assets** are long-term resources of the company, but have no physical existence. They derive their value from intellectual or legal rights and from the value they add to the other assets\(^{25}\). When determining the RAB some regulatory authorities decide not to include the value of these assets. **Working capital**, defined as difference between company’s current assets\(^{26}\) and current liabilities\(^{27}\) is also sometimes excluded from RAB.

The graphs below show the recognition of intangible assets and working capital in the RABs of the investigated markets.

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\(^{25}\) Examples are patents, copyrights, goodwill.

\(^{26}\) Assets that will be turned into cash within a year.

\(^{27}\) Liabilities that will be repaid within a year.
From the graphs above it can be concluded that regulatory authorities of the analyzed markets treat values of intangible assets and working capital differently when calculating the RAB. Both approaches however may be justified.

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28 In Montenegro the value of recognized working capital is limited to 1/12 of the justified operational costs for transmission and 1/8 for distribution. In Albania, 1/12 of the operational costs is also applied for transmission.
Finally, once the RAB has been calculated for the regulatory period, it may be adjusted on yearly basis in case of incentive based regulation. As shown above, this is the case in FYR of Macedonia, Kosovo*, Moldova, Montenegro and Turkey. The table below provides explanations on the approaches applied.

Table 2 *Treatment of RAB during the regulatory period - electricity transmission and distribution*

<table>
<thead>
<tr>
<th></th>
<th>Treatment of RAB during the regulatory period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>RAB is not changed during the regulatory period</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>RAB is not changed during the regulatory period</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>RAB is not changed during the regulatory period</td>
</tr>
<tr>
<td>Moldova</td>
<td>Investments commissioned during the previous year always increase RAB in the following year</td>
</tr>
<tr>
<td>Montenegro</td>
<td>Yearly based revision includes adjustments of investments that are realized below 50% of the value approved for that year</td>
</tr>
<tr>
<td>Turkey</td>
<td>RAB is yearly adjusted by the CPI</td>
</tr>
</tbody>
</table>

While the purpose of incentive based regulation, in principle, is to allow revenues remaining unchanged during the regulatory period and therefore allowing regulated utilities to consume the benefits of cost reductions during that time, the approach of Moldova’s regulator has to be assessed very positively against incentivizing investments. In case of Montenegro the regulator’s approach develops logic against the background that investments are recognized in the RAB before their commission and there has to be control over their implementation with a view not to allow regulated utilities to earn return on not realized investments.

5. *Rate of return*

Regulated service providers typically will only have interest to invest if the recognized return allows them to cover costs of equity and debt finance needed for the realization of the envisaged projects. The rate of return regulators determine has to take into consideration the credit conditions available to particular regulated companies but also to comparable industries since the utilities in the energy sector do not only compete among themselves for financing sources. Furthermore, the rate of return has to enable investors to cover their finance (equity) requirements and secures at least the risk-free rate of interest plus a risk premium reflecting risks specific for the particular sector of energy industry.
**Weighted Average Cost of Capital** (WACC) is a commonly used method for calculation of the rate of return in regulated energy business. As the name suggests, it reflects weighted average of the cost of each individual component of the capital structure. WACC may be determined as pre-tax or post-tax figure. Pre-tax WACC allows not only coverage of finance cost but also tax coverage. Post-tax WACC assumes that the utility already paid the tax. For the estimation of costs of equity usually the Capital Assets Pricing Model is applied.

The regulatory authorities of the analyzed markets reported figures for real pre-tax WACC for electricity transmission and distribution, including the relevant components for its calculation and they are presented in the table below. As mentioned in the previous chapter, Ukraine does not implement the concept of RAB and return on assets; consequently there will be no related information on Ukraine in this chapter.

**Table 3** WACC and its components for electricity transmission and distribution (all in %)

<table>
<thead>
<tr>
<th></th>
<th>WACC (real, pre-tax)</th>
<th>Gearing (debt/(debt+ equity))</th>
<th>Return on equity</th>
<th>Return on debt</th>
<th>Risk free rate</th>
<th>Beta coefficient</th>
<th>Market return</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Albania</strong></td>
<td></td>
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<td></td>
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<tr>
<td>T</td>
<td>5.47</td>
<td>60</td>
<td>8.51531</td>
<td>3.4432</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>D</td>
<td>9.967</td>
<td>60</td>
<td>16.4433</td>
<td>5.65</td>
<td>7.4324</td>
<td>1.32</td>
<td>-</td>
</tr>
<tr>
<td><strong>Bosnia and Herzegovina</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>T35</td>
<td>0.67% on capital value</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>D36</td>
<td>3.50</td>
<td>1.28</td>
<td>3.50</td>
<td>7.10</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

29 Weight is the share of capital component.
31 Equal to treasury bond rate.
32 Return on debt is calculated as the sum of interest payments on long term debt during the year, divided by the total principal on long term debt (the total amount borrowed) at the beginning of the year. The figure for the rate of debt reported in the table is the average for the three years of the regulatory period.
33 The return on equity, risk free rate + country risk and beta coefficient are defined/decided in the regulatory statement that is part of the privatization package.
34 "Risk free rate" includes both risk free rate and country risk.
35 WACC formula exists, but due to non-existent capital market it cannot be calculated. However there is a rate of return determined for transmission.
36 For BH- Republika Srpska.
## Table: Financial Ratios for Various Countries

<table>
<thead>
<tr>
<th>Country</th>
<th>WACC (real, pre-tax)</th>
<th>Gearing (debt/(debt+equity))</th>
<th>Return on equity</th>
<th>Return on debt</th>
<th>Risk free rate</th>
<th>Beta coefficient</th>
<th>Market return</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Croatia</strong></td>
<td>T 5.67 D 4.72</td>
<td>T 21 D 21</td>
<td>6.11</td>
<td>4.91</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td><strong>FYR of Macedonia</strong></td>
<td>T 5.6542 D 6.7265</td>
<td>T 60.69 D 53.35</td>
<td>8.53</td>
<td>8.53</td>
<td>4.68</td>
<td>1</td>
<td>3.85</td>
</tr>
<tr>
<td><strong>Kosovo</strong>*</td>
<td>T 5.07 D 12</td>
<td>T 40 D 40</td>
<td>6.1</td>
<td>13.9</td>
<td>9.1</td>
<td>6</td>
<td>1</td>
</tr>
<tr>
<td><strong>Moldova</strong></td>
<td>T 8.95 D 14.12</td>
<td>T 50 D 35</td>
<td>8.705</td>
<td>13.78</td>
<td>9.13</td>
<td>6</td>
<td>5.26</td>
</tr>
<tr>
<td><strong>Montenegro</strong></td>
<td>T 7.24 D 7.24</td>
<td>T 0.5 D 0.5</td>
<td>10.9</td>
<td>10.9</td>
<td>1.93</td>
<td>0.68</td>
<td>6</td>
</tr>
<tr>
<td><strong>Serbia</strong></td>
<td>T 6.64 D 3.7</td>
<td>T 60 D 50</td>
<td>9</td>
<td>9</td>
<td>0.91</td>
<td>0.7</td>
<td>11.59</td>
</tr>
<tr>
<td><strong>Turkey</strong></td>
<td>T 9.93 D 10.49</td>
<td>T 50 D 50</td>
<td>-</td>
<td>-</td>
<td>0.62</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

### Notes:
- **WACC** is different for every year in the regulatory period (2012-2015). This is the figure for the third regulatory period, i.e. from 1st August 2014 to 31st July 2015. For the past years it was 6.80% and 7.02% respectively.
- **Return on government bonds.**
- **Weighted average interest rate of existing long-term loans of the TSO/MO.**
- **Determined by the government.**
- **As similar utilities internationally.**
- **Beta coefficient is determined yearly based on the corresponding average value of the energy sector of the USA published in DAMODARAN source, compartment Data Sets, Levered an unlevered Betas by Industry. (under the new tariff methodology from 2013 Beta coefficient is established at 47%).**
- **The market return is determined in January of the first year of the regulatory period as the arithmetic mean of the last 10 years in the U.S. (Stock-T.Bills) and published in DAMODARAN in the section Data Sets, Historical Return on Stoks, Bonds and Bills, arithmetic Average, Risk Premium.**
- **WACC is different for every year in the regulatory period (2012-2015). This is the figure for the third regulatory period, i.e. from 1st August 2014 to 31st July 2015. For the past years it was 6.80% and 7.02% respectively.**
- **Set as the sum of risk-free rate and country risk premium. The country risk premium is equal to the premium for the risk of non-payment of a country, multiplied by the volatility coefficient of the capital markets in developing countries.**
- **If parameters not available in Montenegro, the rate shall be equal to the average annual rate of return to German Government bonds for December of the previous year with maturity of 10 years.**
- **Calculated based on international benchmarks.**
- **Required percentage of energy utility for distribution.**

---

37 Return on government bonds.
38 Weighted average interest rate of existing long-term loans of the TSO/MO.
39 Determined by the government.
40 As similar utilities internationally.
41 Weighted average interest rate of existing long-term loans of the DSO.
42 Treasury bonds risk-free rates of USA with maturity more than 10 years, according to statistics published on Bloomberg.
43 Beta coefficient is determined yearly based on the corresponding average value of the energy sector of the USA published in DAMODARAN source, compartment Data Sets, Levered an unlevered Betas by Industry. (under the new tariff methodology from 2013 Beta coefficient is established at 47%).
44 The market return is determined in January of the first year of the regulatory period as the arithmetic mean of the last 10 years in the U.S. (Stock-T. Bills) and published in DAMODARAN in the section Data Sets, Historical Return on Stoks, Bonds and Bills, arithmetic Average, Risk Premium.
45 WACC is different for every year in the regulatory period (2012-2015). This is the figure for the third regulatory period, i.e. from 1st August 2014 to 31st July 2015. For the past years it was 6.80% and 7.02% respectively.
46 Set as the sum of risk-free rate and country risk premium. The country risk premium is equal to the premium for the risk of non-payment of a country, multiplied by the volatility coefficient of the capital markets in developing countries.
47 If parameters not available in Montenegro, the rate shall be equal to the average annual rate of return to German Government bonds for December of the previous year with maturity of 10 years.
48 Calculated based on international benchmarks.
49 All figures for 2013.
50 Required percentage of energy utility for distribution.
6. Depreciation

Depreciation is an allocation of asset costs to the accounting period in which the asset provides benefits to the company. The purpose of calculating depreciation is building up funds for the replacement of assets. There are a number of approaches for calculating depreciation, but the most widely used is straight-line/linear depreciation where the asset is written off every year with the same amount. In order to quickly write off an asset and therefore return the invested capital sooner, some regulators use accelerated depreciation where yearly deductions are greater in the first years of asset use. It has to be noted that depreciation used for regulatory tariff setting can deviate from national tax law depreciation rules. The regulatory authorities of the analyzed markets use straight-line depreciation without differentiation between assets acquired before and during the regulatory period (except in Kosovo*). Only in Albania the depreciation method applied is based on fiscal rates. In Ukraine the regulator considers depreciation calculated by a company using a method in line with applicable tax code. However, in practice most of the companies use straight-line depreciation. In Georgia, Kosovo*, Serbia and Turkey the regulators determine assets lives that are used in the allowed revenue calculation. In other cases the regulator accepts the asset lives used by the regulated companies, in line with applicable national accounting standards and rules. The details on the depreciation methods for electricity transmission and distribution are shown in the table below. The information on asset lives in straight-line depreciation explains how quickly the asset costs are actually recovered.

Table 4 Depreciation of electricity transmission and distribution assets

<table>
<thead>
<tr>
<th>Depreciation method applied</th>
<th>Does the regulator define asset lives for the regulatory purposes?</th>
<th>Asset lives (in years)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Transmission</td>
<td>distribution</td>
</tr>
<tr>
<td>Albania</td>
<td>Fiscal rates</td>
<td>No</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>Straight-line</td>
<td>No</td>
</tr>
</tbody>
</table>

Based on the Law on Fiscal Rates, the Ministry of Economy issues every year Decision on fiscal rates and the regulator takes over the relevant depreciation rates.
<table>
<thead>
<tr>
<th>Country</th>
<th>Depreciation method applied</th>
<th>Does the regulator define asset lives for the regulatory purposes?</th>
<th>Asset lives (in years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Croatia</td>
<td>Straight- line</td>
<td>No</td>
<td>Buildings – 40, electricity equipment – 33 (primary), electricity equipment – 15 (secondary)</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Straight- line</td>
<td>No</td>
<td>Buildings 40, electricity equipment 20,</td>
</tr>
<tr>
<td>Georgia</td>
<td>Straight- line, but other methods also possible</td>
<td>yes</td>
<td>Network 50, substations 50-70</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>Straight- line (the asset lives differ for investments before and after 2012)</td>
<td>yes</td>
<td>Network and substations 40</td>
</tr>
<tr>
<td>Montenegro</td>
<td>Straight- line</td>
<td>No</td>
<td>Buildings 80, network 50, substations 36</td>
</tr>
<tr>
<td>Serbia</td>
<td>Straight- line</td>
<td>yes</td>
<td>Network 40, substations 25</td>
</tr>
<tr>
<td>Turkey</td>
<td>Straight- line</td>
<td>yes</td>
<td>-</td>
</tr>
<tr>
<td>Ukraine</td>
<td>In line with applicable tax code, usually straight- line</td>
<td>no</td>
<td>Network 10, buildings 20</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Network 10, buildings 20[^2]</td>
</tr>
</tbody>
</table>

[^2]: For new incentive based methodology: 0.4-10kV- 30 years, 35-150kV- 40 years, buildings 50 years.
7. Losses

During the transport of electric power through an electricity network, power is lost due to physical and non-physical reasons. Two types of network electricity losses exist:

- *Technical losses* resulting from heating of conductors and transformers during electricity transmission and
- *Non-technical losses* i.e. consumed energy that cannot be billed to an end user. Reasons for these losses include imprecise or incorrect readings, fraud and human error.

Network operators are responsible for the compensation of losses. They purchase appropriate quantities of energy in form of a scheduled supply with the required load profile. The costs of network losses are mostly controllable in a long-run, but not in a short-run (e.g. during the regulatory period). The way they are included in the allowed revenue (if included at all) can be different, e.g. as part of operating costs\(^{53}\) or as separate allowed revenue category\(^{54}\). In any case, the regulator has to ensure network efficiency, not only by recognizing a certain amount of losses, but also by stimulating network operators to reduce them.

The table below provides information on the definition and criteria applied by the regulators of the analyzed markets for recognizing losses in the allowed revenue for electricity transmission and distribution and provides figures for allowed losses and applicable prices that are used for defining the allowed cost.

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\(^{53}\) In case of incentive based regulation the applied efficiency factor then also relates to costs of losses.

\(^{54}\) The maximum value is set for the amount of losses as well as the rule applicable for purchase price.
Table 5 Recognition of losses in the allowed revenue (AR) for electricity transmission and distribution

<table>
<thead>
<tr>
<th>Country</th>
<th>Costs related to network losses recognized in AR for transmission/distribution?</th>
<th>Is there a separate definition of technical and non-technical losses?</th>
<th>Criteria for recognition of losses in the AR</th>
<th>How is price for allowed losses determined?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>T</td>
<td>Yes</td>
<td>Actual costs from the energy balance and investment plans</td>
<td>According to the market model applied, the price for losses for the period 2009-2013 is equal to the cost for public generation</td>
</tr>
<tr>
<td></td>
<td>D</td>
<td>Yes</td>
<td>According to the Regulatory Statement for privatization there was a study for determining losses, done by the auditing company, which determined the level of total technical losses for the year 2008, which is considered as the basis year for determining losses in the future periods based on the scenario losses reduction</td>
<td>Purchase price for allowed losses is determined by the annual tender organized by DSO in accordance with procedures approved by the regulator</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>T</td>
<td>no&lt;sup&gt;55&lt;/sup&gt;</td>
<td>No applicable</td>
<td>Not applicable</td>
</tr>
<tr>
<td></td>
<td>D</td>
<td>Yes</td>
<td>BIH-FBIH: distribution system analysis, plan for reduction of losses BIH-RS: data on the structure and condition of the network and metering devices, structure of consumption of active and reactive electricity, as well as data from the study on losses, benchmarking and other available data, historical data</td>
<td>BIH-FBIH: generation/procurement price BIH-RS: generation/procurement price plus transmission charge</td>
</tr>
<tr>
<td>Croatia</td>
<td>T&amp;D</td>
<td>Yes</td>
<td>Benchmark with similar networks</td>
<td>Price for tariff customers- households, model blue&lt;sup&gt;56&lt;/sup&gt;</td>
</tr>
</tbody>
</table>

<sup>55</sup> Transmission losses are treated as system service and not included in the transmission allowed revenue.

<sup>56</sup> Tariff model for household customers, where active energy without time differentiation is charged.
<table>
<thead>
<tr>
<th>Country</th>
<th>Sector</th>
<th>Recognized in AR</th>
<th>Losses Separation</th>
<th>Criteria for Recognition</th>
<th>Price Determination</th>
</tr>
</thead>
<tbody>
<tr>
<td>FYR of Macedonia</td>
<td>T&amp;D</td>
<td>Yes</td>
<td>No</td>
<td>Historical data, max. 3% for transmission. For distribution DSOs submit also plan for reduction of losses.</td>
<td>Resulting from tender organized by TSO/DSO i.e. market price implemented; regulator approves procedure for tender.</td>
</tr>
<tr>
<td>Georgia</td>
<td>T&amp;D</td>
<td>Yes</td>
<td>There is a definition for normative technical losses; commercial costs not recognized.</td>
<td>Only normative technical losses recognized.</td>
<td></td>
</tr>
<tr>
<td>Kosovo*</td>
<td>T</td>
<td>Yes</td>
<td>No</td>
<td>In setting the loss allowance the regulator takes into account: 1. The outturn level of actual transmission losses for the most recent complete period of 12 successive months for which accurate data is available; 2. Any expected loss reduction that may reasonably be expected to be obtained based on the allowed investment plan during the regulatory period; and 3. The level of transmission losses in comparable transmission systems in countries elsewhere in Europe, taking account of the similarities between the electricity industry in those countries and that of Kosovo.</td>
<td>Average wholesale energy cost calculated by regulator.</td>
</tr>
<tr>
<td>D</td>
<td>Yes</td>
<td>Yes</td>
<td>Regulator sets targets for reduction of losses starting from 2012: 3 percentage points in first 3 years and 2.5 percentage points in the following 3 years.</td>
<td>Average wholesale energy cost calculated by regulator.</td>
<td></td>
</tr>
<tr>
<td>Country</td>
<td>Costs related to network losses recognized in AR for transmission/distribution?</td>
<td>Is there a separate definition of technical and non-technical losses?</td>
<td>Criteria for recognition of losses in the AR</td>
<td>How is price for allowed losses determined?</td>
<td></td>
</tr>
<tr>
<td>---------</td>
<td>---------------------------------------------------------------------------------</td>
<td>-----------------------------------------------------------------</td>
<td>------------------------------------------</td>
<td>------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>Moldova</td>
<td>T</td>
<td>No</td>
<td>Only normative technical losses recognized and are determined as the difference between the amount of electricity measured at points of entry into the electrical networks of transport and the amount of electricity measured in points out of electric transport networks. The losses recognized in the allowed revenue are those related to technological consumption of electricity necessary to operation of equipment involved in the transportation of electricity.</td>
<td>Price of imported electricity</td>
<td></td>
</tr>
<tr>
<td></td>
<td>D</td>
<td>Yes</td>
<td>According to provisions of Instruction for calculating technological consumption in electrical networks, approved by regulator, based on historical data. Commercial losses:[57]: methodology provides for the first 2 years of validity of Methodology a level of 2.0% of the total quantity of electricity in the distribution networks, in the next 2 years - 1.5%, and then - 1.0%</td>
<td>Price of imported electricity plus transmission tariff</td>
<td></td>
</tr>
</tbody>
</table>

\[57\] Treated as stranded costs
<table>
<thead>
<tr>
<th></th>
<th>Costs related to network losses recognized in AR for transmission/distribution?</th>
<th>Is there a separate definition of technical and non-technical losses?</th>
<th>Criteria for recognition of losses in the AR</th>
<th>How is price for allowed losses determined?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montenegro</td>
<td>T</td>
<td>yes</td>
<td>The total losses in the transmission system are set as the difference between the total electricity entering the transmission system and the electricity leaving the transmission system, are calculated as the average of realization for the period of three years preceding the current one</td>
<td>Weighted average purchase electricity price</td>
</tr>
<tr>
<td></td>
<td>D</td>
<td>yes</td>
<td>The Agency sets the allowed losses in the distribution system for each year of the regulatory period based on the study for reduction of losses in the distribution system revised by an independent eligible institution in Montenegro. In the case that a DSO does not submit the study, the allowed losses in the distribution system for each year of the regulatory period shall be set on the level that is not higher than the level set for the current year.</td>
<td></td>
</tr>
<tr>
<td>Serbia</td>
<td></td>
<td>Yes</td>
<td>Justified electricity lost rate in one year set based on: realized loss rate in previous years, analysis of the system, benchmark with neighboring transmission/distribution systems, loss reduction plan and measures for its implementation.</td>
<td>Weighted average purchase electricity price</td>
</tr>
<tr>
<td>Ukraine</td>
<td>Costs related to network losses recognized in AR for transmission/distribution?</td>
<td>Is there a separate definition of technical and non-technical losses?</td>
<td>Criteria for recognition of losses in the AR</td>
<td>How is price for allowed losses determined?</td>
</tr>
<tr>
<td>---------</td>
<td>---------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------</td>
<td>---------------------------------------------</td>
<td>-------------------------------------------</td>
</tr>
<tr>
<td>T</td>
<td>no</td>
<td>not applicable</td>
<td>not applicable</td>
<td>not applicable</td>
</tr>
<tr>
<td>D</td>
<td>Not explicitly, but the relevant costs are included in retail tariffs/end-user prices</td>
<td>There is a definition for normative technical losses and non-technical losses; non-technical losses are not recognized</td>
<td>The level of normative technological losses determined by the simulation results based on network topology, normal mode of the network operation and volumes of distributed electricity</td>
<td>not applicable</td>
</tr>
</tbody>
</table>
With the exception of Bosnia and Herzegovina and Ukraine, costs related to network losses are recognized in the allowed revenue for transmission in all analyzed markets. However, in Bosnia and Herzegovina the losses are treated as system service with an allowed percentage of losses (1.84%) and an applicable price not part of the transmission allowed revenue calculation. **Allowed revenues for distribution include costs related to network losses in all investigated markets**, with the exception of Ukraine, where distribution losses are considered in the formula for retail price calculation.

The definitions of transmission losses do not distinguish between technical and non-technical (commercial) losses i.e. they are simply calculated as difference between input and output of energy. In Georgia and Moldova there is even a definition of normative (standardized) technical network losses that per default exclude any non-technical losses. In those cases where more than normative technical losses are recognized in the allowed revenue, the criteria used mainly rely on historical data on losses and benchmarking with other comparable networks.

For **electricity distribution** there is a separate definition of commercial losses in Kosovo* and Moldova. In Bosnia and Herzegovina there is no definition of commercial losses, but the regulator of BIH entity Republika Srpska allows certain percentages for commercial losses. In Ukraine a definition of normative (standardized) technical network losses is applied.

When calculating the level of losses related costs in the allowed revenue, regulators use different supply or purchase electricity for distribution prices (including transmission charges for distribution losses). Only in FYR of Macedonia this price is explicitly market based, i.e. the TSO/DSO has to organize a tender for purchasing electricity to cover losses. The procedure of this tender is approved by the regulator.

Currently allowed percentages of losses in transmission and distribution network are presented on the figure below. The allowed level of losses in the transmission network in Croatia has not been determined yet.
Figure 6: Allowed levels of losses in the transmission networks (in %)

Figure 7: Allowed weighted average levels of losses in the distribution networks (in %)[58]

[58] In some cases weighted average level of losses is not available, but only the range of recognized levels of losses. In Ukraine the data on losses refer to minimal, maximal and average losses (but not weighted average).
The percentages of allowed commercial losses for electricity distribution are separately expressed only in Bosnia and Herzegovina-Republika Srpska. Their range is from 2,58% to 3,12% (the figure above shows the aggregate level of allowed losses).

8. Deducted revenues

Transmission and distribution system operators may earn revenues from non-regulated activities performed by using the same assets already included in RAB, e.g. revenues from congestion or from reconnection. In order to avoid double earnings from the same assets, the regulators often deduct such non-regulated revenues from the regulated allowed revenue. In this context it has to be noted that deduction of congestion revenues from the regulated allowed revenue, if not used for investments aiming to reduce congestion, can serve as appropriate ‘negative investment incentive’ with a view to promote necessary system upgrades.

The figure below explains to which extent the regulatory authorities of the investigated markets deduct some non-regulated revenues from the transmission and distribution allowed revenue.

Figure 8 Deduction of non-regulated revenues from the regulated allowed revenue in electricity transmission and distribution

![Diagram showing deduction of non-regulated revenues from regulated allowed revenue in various countries.](image-url)
Where non-regulated revenues are deducted from the calculated allowed revenue for electricity transmission, the following mechanisms apply:

- **Albania**
  - **Transmission**: revenues from capacity allocation
  - **Distribution**: no deduction

- **Bosnia and Herzegovina**
  - **Transmission**: ITC mechanism revenues, revenues from cross-border transmission capacity allocation etc.
  - **Distribution**: revenues that a DSO realizes with the licensed assets, such as the revenues from the sale of by-products, revenues from activating its own outputs, revenues from the sale of assets, separated part of the revenue of the period based on realization of the donated assets and other revenues realized using the licensed assets included in the regulatory base.

- **FYR of Macedonia**
  - **Transmission**: revenues from capacity allocation on interconnectors, ITC mechanism revenues, all compensations for network connections related to maintenance and operation of the connection assets and all other revenues that do not arise from the use of transmission grid.
  - **Distribution**: revenues from non-regulated activities earned by using regulated assets, e.g. revenues from reconnection.

- **Kosovo**: currently there are no revenues deducted, but there is a non-exhaustive list of «excluded services» for which the TSO/MO and DSO levy a charge and the revenues resulting from them are then deducted from transmission/distribution allowed revenue: the carrying out of works the cost of which is required to be reimbursed by a user of the system or a third party, relocation of any electric line or electrical plant, movement of any electric line, electrical plant, or metering equipment that forms part of the transmission/distribution system to accommodate the extension, redesign, or redevelopment of any premises on which the asset in question is located or to which it is connected, the cost of which is to be borne by a user of the system or a party requesting the relocation, revision of electric lines and electrical plant to the extent required by any user of the transmission/distribution system to provide a higher degree of security than is required TSO’s/DSO’s license (*Transmission System Security and Planning Standards*), provision of any metering service that is not already remunerated under any other charge in respect of an excluded service.

- **Montenegro**
  - **Transmission**: revenues from telecommunications services

- **Serbia**
  - **Transmission**: revenues arising from the activities on electricity market organisation and management, revenues arising from the mechanisms for electricity transit compensation,

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59 For distribution there are no deducted revenues.
revenues earned through allocating interconnection capacities, revenues collected by balancing activities, revenues arising from the sales of side-products and services, revenues from activation of own goods and outputs, revenues collected by selling regulated assets, revenues arising from the guarantee of origin, revenues arising from damage compensation, revenues arising from electricity suspension and other revenues.

- Distribution: revenues arising from the sales of side-products and services, revenues from activation of own goods and outputs, revenues collected by selling regulated assets, revenues arising from damage compensation, revenues arising from electricity delivery suspension and other revenues.

9. Quantities

Once the allowed revenue is calculated, the quantity of sold products needs to be established for the determination of the actual tariff. Overestimated or underestimated quantities may substantially influence the level of tariffs. This is the reason why most of the regulators revise and finally approve the level of quantities to be used for determination of tariffs. In order to be transparent when calculating or approving tariffs, regulators should establish and publish criteria for revising or approving these quantities.

The table below provides an overview of the criteria implemented for revision and determination of quantities used for calculation of transmission and distribution tariffs.

<p>| Table 6 Sources of quantities used for electricity transmission and distribution tariff calculation |
|---|---|
| Sources of quantities used for transmission tariff calculation | Sources of quantities used for distribution tariff calculation |
| Albania | BIH-FBIH: DSO’s planned quantities that are part of energy balance harmonized with ISO; BIH-RS: DSO’s planned quantities; regulator has the right to check if in line with balancing rules, optimal use of capacity and energy balance and to modify, if needed. |
| Bosnia and Herzegovina | Quantities proposed by the DSO and controlled by the regulator to avoid discrepancies with the quantities reported by other relevant market participants |
| Energy balance for the next year prepared by the TSO | Energy balance for the next year prepared by the ISO |</p>
<table>
<thead>
<tr>
<th>Country</th>
<th>Sources of quantities used for transmission tariff calculation</th>
<th>Sources of quantities used for distribution tariff calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Croatia</td>
<td>Data from TSO</td>
<td>Data from DSO</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Energy balance adopted by the Government, TSO’s planned quantities and historical data</td>
<td>Energy balance adopted by the Government, DSO’s planned quantities and historical data</td>
</tr>
<tr>
<td>Georgia</td>
<td>Energy balance approved by the ministry based on actual data of the previous year</td>
<td>Energy balance approved by the ministry based on actual data of the previous year</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>Yearly energy balance approved by the ministry</td>
<td>Yearly energy balance approved by the ministry</td>
</tr>
<tr>
<td>Moldova</td>
<td>Contract between TSO and suppliers</td>
<td>Procurement contract between DSO and suppliers</td>
</tr>
<tr>
<td>Montenegro</td>
<td>Energy balance approved by the Government(^{61})</td>
<td>Energy balance approved by the Government</td>
</tr>
<tr>
<td>Serbia</td>
<td>Planned quantities proposed by TSO, subject to regulators’ analysis</td>
<td>Planned quantities proposed by DSO, subject to regulators’ analysis</td>
</tr>
<tr>
<td>Ukraine</td>
<td>Quarterly forecast based on energy balance approved by the relevant ministry</td>
<td>The volume of electricity distributed on the appropriate voltage level includes volumes of transformation of electricity from high voltage to a lower level, volumes of electricity supplied to customers for this voltage level, regardless of the connection point of customers to networks. The volume is based on the energy balance but regulator considers also actual volumes of the previous year</td>
</tr>
</tbody>
</table>

From the information presented in the table above it can be concluded that in the majority of cases regulators prefer having a concrete and provable source of data for quantities used for tariff calculation, such as energy balance or concluded contracts. However, in most of the markets regulators also have the right to change the amounts of volume taken over from energy balances or other sources, for the purpose of tariff calculation. The exception is Moldova, where the regulator uses quantities from the contracts for calculating tariffs and these quantities are then revised in the scope of correction of the allowed revenue for the next year (see Chapter 10 on correction).

\(^{61}\) In general, the regulator is not allowed to change the energy balance approved by the Government, but in 2011 the energy balance was changed in order to include also the level of distribution losses allowed by the regulator.
10. Correction

After expiry of the regulatory period regulators have the opportunity to calculate the difference between the allowed and actually earned revenue. These two values are always different due to the difference between planned and actual quantities, but also because of different planned and realized costs. The amount of over/under-recovery is then to be compensated in the next regulatory period.

The methodologies for the calculation of transmission and distribution allowed revenues and tariffs in the analyzed markets envisage calculation of correction factor based on both realized quantities and costs. The exceptions are Croatia and Ukraine for both transmission and distribution and Turkey for distribution – in these cases regulators calculate correction based only on quantities. Specific approaches are applied in FYR of Macedonia and Kosovo*, where the regulator multiplies the difference between allowed and realized revenue by a predefined interest rate\(^62\). In Moldova the differences between planed and realized values of relevant elements of the allowed revenue, positive or negative, are discounted at the rate of return and then included in the allowed revenue for the next period.

11. Ancillary services

Ancillary services are services necessary for safe, reliable and stable operation of the network. The table below shows to which extent costs of these services are included in the allowed revenue for transmission.

\(^62\) In FYR of Macedonia this is the average passive interest rate published by the National Bank. In Kosovo* it is determined as the sum of EURIBOR rate and S, where the S reflects the premium payable by the licensee for short-term loans above the EURIBOR rate.
Table 7 Costs of ancillary services recognized in the allowed revenue for electricity transmission

<table>
<thead>
<tr>
<th>Country</th>
<th>Costs of ancillary services included in allowed revenue?</th>
<th>Types of ancillary services included in the allowed revenue</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>Yes</td>
<td>all</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>no</td>
<td>n.a.</td>
</tr>
<tr>
<td>Croatia</td>
<td>Yes</td>
<td>- secondary and tertiary regulation,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- reactive energy production,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- capability for island operation of a part of the power</td>
</tr>
<tr>
<td></td>
<td></td>
<td>system,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- capability of a power plant to operate without any</td>
</tr>
<tr>
<td></td>
<td></td>
<td>external electricity supply,</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- capability of a power plant for black start</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Yes</td>
<td>Costs of frequency regulation service and exchange power</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(primary, secondary and tertiary regulation), voltage</td>
</tr>
<tr>
<td></td>
<td></td>
<td>regulation and the share in the establishment of the power</td>
</tr>
<tr>
<td></td>
<td></td>
<td>system (black start).</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>Yes</td>
<td>Ancillary services currently not contracted</td>
</tr>
<tr>
<td>Moldova</td>
<td>no</td>
<td>n.a.</td>
</tr>
<tr>
<td>Montenegro</td>
<td>Yes</td>
<td>- The primary control;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Secondary regulation;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Tertiary regulation;</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Voltage regulation - reactive power (without reimbursement)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Supply of reactive power and</td>
</tr>
<tr>
<td></td>
<td></td>
<td>- Ability to restart the power system from black start</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(without reimbursement)</td>
</tr>
<tr>
<td>Serbia</td>
<td>yes</td>
<td>Costs of frequency regulation service and exchange power</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(primary, secondary and tertiary regulation), voltage</td>
</tr>
<tr>
<td></td>
<td></td>
<td>regulation and the share in the establishment of the power</td>
</tr>
<tr>
<td></td>
<td></td>
<td>system (black start).</td>
</tr>
<tr>
<td>Ukraine</td>
<td>no (reserves are procured by market operator and relevant costs are included in the wholesale price of electricity)</td>
<td>not applicable</td>
</tr>
</tbody>
</table>

---

63 According to the existing model of providing ancillary services in BIH, the relevant financial transactions take place outside the system operator.
64 These costs are covered by the income from ancillary services rendered by operator at tariffs approved by the methodology developed by the regulator (Nr.245 of 02.05.2007).
Regulation of electricity supply

According to the Energy Community acquis communautaire Contracting Parties may impose so-called “public service obligations” on energy companies which may be related, among other, to the price of supply. Such obligations need to be clearly defined, transparent, non-discriminatory, verifiable and shall guarantee equality of access for electricity undertakings to consumers. Against this background, in many countries regulated end-user prices for both households and non-household customers still exist. It has to be noted that, in case regulated energy prices are set at levels that do not allow recovery of costs, they tend to establish a barrier for the development of competition and effective market opening.

When regulating end-user prices, several components are added to the network charges:

- commodity price i.e. cost of providing electricity,
- supply service costs,
- taxes, levies, regulatory fees, charge for market operator’s services, support for renewables etc.

Under certain circumstances final electricity prices also include components such as bad debts or non-collection rate.

The table below explains how these elements are included in the regulated electricity end-user prices. Please note that the costs of transmission and distribution charged through end-user electricity price by the supplier are then transferred to the operators of transmission and distribution system, in line with applicable tariff systems.

---

65 Art. 3(2) of the Electricity Directive. For the electricity sector the acquis foresees public service obligations in particular in the context of so-called “universal service obligations”: Art.3(3) of the Electricity Directive all household customers and small enterprises, as defined by the acquis, are entitled to enjoy universal service, i.e. is the right to be supplied with electricity of a specified quality within their territory at reasonable, easily and clearly comparable, transparent and non-discriminatory prices. A related provision does not exist in the gas acquis.

### Table 8 Structure of allowed revenue for electricity supply

<table>
<thead>
<tr>
<th>Country</th>
<th>Structure of maximally allowed revenue (MAR) for regulated electricity supply</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>[ \text{MAR}_t = \text{costs of electricity purchase} + \text{transmission costs} + \text{distribution costs} + \text{supply service costs} + \text{bad debt allowance} ]</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>[ \text{MAR}_t = \text{costs of electricity purchase} + \text{transmission costs} + \text{distribution costs} + \text{supply service costs} ]</td>
</tr>
<tr>
<td>Croatia</td>
<td>[ \text{MAR}_t = \text{costs of electricity purchase} + \text{supply service costs} + \text{transmission costs} + \text{distribution costs} ]</td>
</tr>
</tbody>
</table>
| FYR of Macedonia     | \[ \text{MAR}_t = \text{O}_t + \text{D}_t + \text{CPT}_t + \text{E}_t + \text{TNU}_t + \text{MO}_t + \text{DN}_t + \text{Mt} + \text{LC}_t - \text{K}_t \] Where: \[
\begin{align*}
\text{O}_t & = \text{operating costs in year } t \\
\text{D}_t & = \text{depreciation in year } t \\
\text{CPT}_t & = \text{costs pass-through in year } t \\
\text{E}_t & = \text{costs for electricity purchase} \\
\text{TNU}_t & = \text{costs for transmission in year } t \\
\text{MO}_t & = \text{costs for electricity market operator in year } t \\
\text{DN}_t & = \text{costs for distribution in year } t \\
\text{Mt} & = \text{margin for activity electricity supply of tariff consumers} \\
\text{LC}_t & = \text{recognized bad debts in year } t \\
\text{K}_t & = \text{correction element in year } t
\end{align*}
\] |
| Kosovo*              | \[ \text{MAR}_t = \left( \text{RETR}_t + \text{WCLC}_t + \text{WHPC}_t + \text{PST}_t - \text{NTFR}_t + \text{KREV}_t \right) / \left(1 - \text{BDTAt} \right) \] Where: \[
\begin{align*}
\text{RETR}_t & = \text{allowed retail costs in year } t, \text{ which is set at Annual Updates} \\
\text{WCLC}_t & = \text{allowed working capital costs in year } t \\
\text{WHPC}_t & = \text{allowed wholesale power costs in year } t \\
\text{PST}_t & = \text{Pass-Through Costs in year } t \\
\text{NTFR}_t & = \text{non-tariff revenues in year } t \\
\text{KREV}_t & = \text{the revenue correction factor in year } t \\
\text{BDTAt} & = \text{the bad debt allowance in year } t, \text{ set as a percentage } (\%) 
\end{align*}
\] |
| Moldova              | \[ \text{MAR}_t = \text{costs of electricity purchase} + \text{transmission costs} + \text{distribution costs} + \text{supply service costs} \] |
| Montenegro           | \[ \text{MAR}_t = \text{the operating costs for the regulated activity (OC}_t + \text{depreciation (Dt) + return on assets (RAI)} \] |
| Serbia               | \[ \text{MAR}_t = \text{OPEX}_t + \text{D}_t + \text{NEE}_t + \text{TUoSt} + \text{DUoSt} + \text{ARCR}_t + \text{CF}_t \] Where: \[
\begin{align*}
\text{t} & = \text{regulatory period,} \\
\text{OPEX}_t & = \text{operating expenditure in period } t \\
\text{D}_t & = \text{depreciation costs in period } t \\
\text{NEE}_t & = \text{costs of electricity procurement from wholesale supplier including also associated costs, in period } t \\
\text{TUoSt} & = \text{transmission use of system charges in period } t \\
\text{DUoSt} & = \text{distribution use of system charges in period } t \\
\text{Pt} & = \text{profit of the public supplier in period } t \\
\text{CF}_t & = \text{correction factor in period } t
\end{align*}
\] |

---

67 Applicable only to household customers. Customers that can choose their suppliers pay network charges separately from electricity and supply costs.
In case the price of commodity changes, this influences the cost of providing that commodity to the customers by the suppliers. If supply is regulated, the regulatory authority has to define a mechanism to take these changes into account when determining the end-user prices. This mechanism should describe the cases, in which change of commodity prices will result in a change of the final price as well as whether related costs are treated as pass-through cost or some limitation of cost level is introduced.

### Table 9 Treatment of change in commodity prices in the final electricity price regulation

<table>
<thead>
<tr>
<th>Country</th>
<th>Treatment of change in commodity prices in the final price regulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>Allowed revenue for retail public supply updated annually based on change in wholesale electricity costs.</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>BIH-FBiH: no automatic mechanism, the final prices are changed by new tariff proceeding i.e. on the request of a supplier</td>
</tr>
<tr>
<td>Croatia</td>
<td>no automatic mechanism, the final prices are changed by request of energy suppliers based on tariff system for electricity generation</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>no automatic mechanism, the final prices are changed by new tariff proceeding (taken into account every year)</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>maximal allowed revenue for supply is updated annually taking into consideration also wholesale electricity costs (see Table 8)</td>
</tr>
<tr>
<td>Moldova</td>
<td>The change in commodity price is treated as pass-through cost and the final price is changes if this commodity-related cost influences the total level of allowed costs by more than 1%</td>
</tr>
</tbody>
</table>

---

68 Whole amount of cost change will be carried over to the customers.
<table>
<thead>
<tr>
<th>Country</th>
<th>Treatment of change in commodity prices in the final price regulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Montenegro</td>
<td>The change in commodity prices is taken into account when calculating correction element for the regulatory year (i.e. correction calculated every year during the regulatory period)</td>
</tr>
<tr>
<td>Serbia</td>
<td>no automatic mechanism, but suppliers may submit to the regulator price proposals after any change in electricity purchase price</td>
</tr>
<tr>
<td>Turkey</td>
<td>Allowed revenue and prices are revised quarterly based on actual costs and prices</td>
</tr>
<tr>
<td>Ukraine</td>
<td>According to the procedure of retail electricity tariff calculation for customers (except households) licensees that the retail price for electricity supplied at regulated tariff, adopted by NERC, is calculated monthly. The price of electricity as a commodity is taken as estimated average purchase price of electricity in the month for which retail prices are set and includes projected wholesale market prices for this month (approved by NERC) as well as the price at which the licensee in accordance with the contract purchased electricity directly from the producer, or the tariff for electricity production by the licensee in own power station in the billing month, and deviation of paying for purchased electricity, taking into account the adjustments for previous periods. Changes in the price of electricity as a commodity affect the level of the estimated rate for the households, but as tariffs for households are fixed, it does not automatically change the actual end-user price for households. For other consumers, retail tariffs are calculated according to the formula provided in the license conditions and rules of the supply at regulated tariffs, which includes the wholesale market price, the tariff for distribution, supply and take into account normative technological losses in networks. In the case of monthly changes of wholesale electricity prices, end-user price for consumers changes accordingly.</td>
</tr>
</tbody>
</table>

From the table above it can be concluded that a change in commodity prices result in changes of final prices mainly on the request of regulated suppliers and, generally, the whole amount of cost is carried over to the customers. However, the change of regulated end-user prices on the ground of, among other, input commodity prices is assessed every year in FYR of Macedonia, Kosovo* and Albania, quarterly in Turkey and even monthly in Ukraine for customers other than households. In Moldova, this change is performed in case the pass-through costs, including commodity-related costs, exceed 1% of the total allowed costs.

Supply service costs, such as costs for billing, contract administration or customer service/call centers, are always included in the allowed revenue for electricity supply (see Table 8 above). Sometimes also a retail margin/profit is allowed in the regulated revenue of suppliers (e.g. in FYR of Macedonia, Montenegro, Serbia and Ukraine).

Having in mind that suppliers collect revenues from delivering a final product to customers, it is reasonable to consider whether the allowed revenue for supply should include an allowance for bad debt or a non-collection rate. The difference between these two terms only develops from
the regulatory practice\textsuperscript{69}. However, regulators normally do not simply take over the amount of companies’ bad debt allowance into the allowed revenue, but define criteria and formulas for calculating the allowed expense. Before approving a bad debt allowance, the regulatory authorities typically ask companies to prove that they employed all possible measures to collect their receivables and also take into consideration whether the costs for collecting debt are bigger than the losses caused by writing them off.

The figure below shows which regulatory authorities include bad debt allowance, i.e. non-collection rate, into the allowed revenue for electricity supply.

Figure 9 Treatment of bad debt for the electricity supply

\textsuperscript{69} The accounting term used is “bad debt allowance”. Bad debts are accounts receivable that will likely remain uncollectable and will be written off. Bad debts appear as an expense on the company's income statement, thus reducing net income. In general, companies make an estimate of bad debt expenses that might be incurred in the current time period based on past records as part of the process of estimating earnings. Most companies make a bad debt allowance since it is unlikely that all of their debtors will pay them in full (www.investorwords.com).
The **maximally allowed percentages of bad debt included in the regulated revenues of suppliers** are:

- 14.85 starting form 2012 and 1% reduction per year by 2014 % in Albania
- 1% in Bosnia and Herzegovina
- 3.5% in FYR of Macedonia
- 5% for 3 years starting from 2012 and 4% for the next 3 years in Kosovo*.

Finally, the regulatory authorities of the analyzed markets were asked whether some other **charges or levies** are explicitly included in the allowed revenue for electricity supply, in particular regulatory fees and-or support for renewable energy. While all justified costs borne by the regulated suppliers are included in the overall amount of allowed costs and the final tariff, i.e. they are always treated as pass-through costs, the question aimed to identify whether these costs are transparent to the final customers. The tables below summarize the responses received.

**Table 10 Financing of regulatory authority and final tariffs and prices**

<table>
<thead>
<tr>
<th>Country</th>
<th>Are the costs for financing the regulatory authority included in tariff? If yes, in which tariff(s)?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>Yes, implicitly, in tariffs for all regulated activities</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>Yes, implicitly, in tariffs for all regulated activities</td>
</tr>
<tr>
<td>Croatia</td>
<td>Yes, implicitly, in tariffs for all regulated activities (0.05% of revenues of all licensed companies plus some administrative charges)</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Yes, implicitly, in tariffs for all regulated activities (may not exceed 0.1% of revenues of all licensed companies, for 2013- 0.037%)</td>
</tr>
<tr>
<td>Georgia</td>
<td>Yes, implicitly, in tariffs for all regulated activities</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>Yes, implicitly, in tariffs for all regulated activities (may not exceed 2% of annual revenue)</td>
</tr>
<tr>
<td>Moldova</td>
<td>Yes, implicitly, in tariffs for transmission, distribution and supply</td>
</tr>
<tr>
<td>Montenegro</td>
<td>Yes, implicitly, in tariffs for all regulated activities</td>
</tr>
</tbody>
</table>

---

70 Throughout the table ‘implicitly’ indicates that the costs are not separately displayed to customers.
71 The regulator is financed through license fees- for issuing and yearly for usage. The fees for issuing are expressed in Euro and yearly fees in Euro cent per MW and MWh.
Are the costs for financing the regulatory authority included in tariff? If yes, in which tariff(s)?

<table>
<thead>
<tr>
<th>Country</th>
<th>Answer</th>
<th>Explanation</th>
</tr>
</thead>
</table>
| Serbia       | Yes, implicitly, in the transmission tariff. Regulatory charge is part of operational costs of the electricity transmission operator. This regulatory charge is calculated according to the following formula:  
\[ R_C^t = 0.9\% \times (A_OPEX^t + D_t + WACC^t \times R_A^t) \]  
where:  
- \( A_OPEX^t \): adjusted operating cost calculated before inclusion of purchasing value of electricity for balancing and regulatory charge in period \( t \) |
| Turkey       | Yes, implicitly, in the transmission tariff | |
| Ukraine      | No, regulatory authority is financed through the state budget | |

Table 11 *Inclusion of support for electricity from renewable sources in electricity tariff(s)*

<table>
<thead>
<tr>
<th>Country</th>
<th>Is RES support allowance included in tariff? If yes, in which tariff(s)?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>Yes, in the tariff for wholesale public supply(^{72})</td>
</tr>
</tbody>
</table>
| Bosnia and Herzegovina | Yes, paid by all final customers and expressed separately on electricity bill (in supply tariff)  
BIH-RS: 0.0009 BAM/kWh,  
BIH-FBIH: 0.001 BAM/kWh (0.4kV customers and public lighting), 0.0008 BAM/kWh (10kV customers),  
0.0007 BAM/kWh (35kV customers), 0.0005 BAM/kWh (110kV and above customers),  
1€=1.95583BAM | |
| Croatia          | Yes, 0.05kn/kWh for 2012, paid by all final customers and displayed separately on electricity bill | |
| FYR of Macedonia | Yes, in the tariff for organization and operation of the market -0.049€/MWh, paid by all final customers (market operator buys electricity from preferential generators and pays feed-in tariff); not visible on the bill | |

\(^{72}\) Until 2013 the RES support/feed in tariff is calculated pursuant to the methodology for calculating the price of new HPP up to 15 MW which has taken in consideration the Law on Concessions. The calculating formula of this methodology is based on the price of the imported electricity by Wholesale Public Supplier of the previous year plus 10% bonus. Starting from 2014 the regulator must apply the Law No. 138 2:05.2013 on RES which defines the calculation formula applicable for each renewable resource technology while elements of the formula will be determined by the regulator every three years.
<table>
<thead>
<tr>
<th>Country</th>
<th>Is RES support allowance included in tariff? If yes, in which tariff(s)?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Georgia</td>
<td>No</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>Yes, in supply tariff, not visible on the electricity bill</td>
</tr>
<tr>
<td>Moldova</td>
<td>Yes, in supply tariff, not visible on the electricity bill</td>
</tr>
<tr>
<td>Montenegro</td>
<td>No, for the time being, but upon the adaptation of the New Energy Law this RES support allowance shall be included in tariff</td>
</tr>
<tr>
<td>Serbia</td>
<td>No</td>
</tr>
<tr>
<td>Turkey</td>
<td>Yes, in supply tariff</td>
</tr>
<tr>
<td>Ukraine</td>
<td>Yes, costs of connection of RES generation to the network-in the distribution/transmission tariff- not visible on the bill; Feed in tariff is included in the wholesale price of electricity-the share of RES in wholesale price is visible on the bill on the annual basis.</td>
</tr>
</tbody>
</table>

12. Universal service

In the case of electricity, the previously described process of end-user price regulation usually refers to universal service provision\(^{73}\). This universal service may be provided by a supplier of last resort. However, the Electricity Directive neither provides definition of a supplier of last resort nor defines the circumstances under which it should be applied. In the light of this, the European Regulators Group for Electricity and Gas (ERGEG) in 2009 investigated the use of this term in the energy sectors of EU countries\(^ {74}\).

\(^{73}\) For the electricity sector the acquis foresees public service obligations in particular in the context of so called “universal service obligations”: Art.3(3) of the Electricity Directive all household customers and small enterprises, as defined by the acquis, are entitled to enjoy universal service, i.e. is the right to be supplied with electricity of a specified quality within their territory at reasonable, easily and clearly comparable, transparent and non-discriminatory prices. A related provision does not exist in the gas acquis.

\(^{74}\) Status review of the definitions of vulnerable customer, default supplier and supplier of last resort, ERGEG. July 2009, available at http://www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Customers/Tab/E09-CEM-26-04_StatusReview_16-Jul-09.pdf. The ERGEG survey also explored whether the similar term of a default supplier also exists and in which cases it is used. The ERGEG analysis showed that the majority of EU countries have a definition of the term supplier of last resort but only less than half of the EU Member States use a definition for the term default supplier. However, the assessment also showed that it is not unusual for the supplier of last resort to also act as default supplier and vice versa. A supplier of last resort is mostly activated when a (chosen or default) supplier goes bankrupt, while default suppliers usually step in when a customer is inactive on the market, i.e. did not choose a supplier.
In the Energy Community Contracting Parties and other analyzed markets the application of default suppliers and/or suppliers of last resort is described in the table below.
### Table 12: Application of default supplier and supplier of last resort as universal service in electricity supply

<table>
<thead>
<tr>
<th>Country</th>
<th>Definition of default supplier (DS)</th>
<th>Definition of supplier of last resort (SLR)</th>
<th>End-user customers eligible for being supplied by DS/SLR</th>
<th>Is there a special tariff methodology for DS?</th>
<th>Is there a special tariff methodology for SLR?</th>
<th>Share of HH supplied under a default tariff (out of total HH)</th>
<th>Time limit for supply by SLR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>no</td>
<td>yes</td>
<td>all</td>
<td>no</td>
<td>no</td>
<td>100%</td>
<td>No time limit</td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>yes</td>
<td>yes</td>
<td>all</td>
<td>Yes</td>
<td>yes</td>
<td>100%</td>
<td>60 days</td>
</tr>
<tr>
<td>Croatia</td>
<td>yes, for HH</td>
<td>yes, for all customers</td>
<td>HH for DS, all for SLR</td>
<td>Yes</td>
<td>yes</td>
<td>99.9%</td>
<td>No time limit</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>no</td>
<td>yes</td>
<td>HH and small enterprises</td>
<td>yes</td>
<td>yes</td>
<td>100%</td>
<td>No time limit</td>
</tr>
<tr>
<td>Kosovo*</td>
<td>no</td>
<td>yes</td>
<td>all</td>
<td>no</td>
<td>no</td>
<td>100%</td>
<td>No time limit</td>
</tr>
<tr>
<td>Moldova</td>
<td>no</td>
<td>yes</td>
<td>all</td>
<td>not applicable</td>
<td>yes</td>
<td>100%</td>
<td>No time limit</td>
</tr>
<tr>
<td>Montenegro</td>
<td>yes</td>
<td>yes</td>
<td>all</td>
<td>no</td>
<td>yes</td>
<td>100%</td>
<td>12 weeks</td>
</tr>
<tr>
<td>Serbia</td>
<td>yes&lt;sup&gt;75&lt;/sup&gt;</td>
<td>yes&lt;sup&gt;76&lt;/sup&gt;</td>
<td>DS: HH and SME&lt;sup&gt;77&lt;/sup&gt;/ SLR: final customers not entitled to public supply</td>
<td>Yes</td>
<td>no</td>
<td>100%</td>
<td>60 days</td>
</tr>
<tr>
<td>Turkey</td>
<td>no</td>
<td>yes</td>
<td>all</td>
<td>Not applicable</td>
<td>-</td>
<td>-</td>
<td>No time limit</td>
</tr>
<tr>
<td>Ukraine</td>
<td>no&lt;sup&gt;78&lt;/sup&gt;</td>
<td>no</td>
<td>all</td>
<td>no</td>
<td>no</td>
<td>100%</td>
<td>No time limit</td>
</tr>
</tbody>
</table>

---

<sup>75</sup> In Serbia “default supplier” is defined in the Energy Law as a “public supplier” (universal service; sale of electricity to households and small customers at regulated prices.

<sup>76</sup> In Serbia SLR is defined in Articles 145 and 146 of the Energy Law as “Reserve Supplier”.

<sup>77</sup> As of 1st January 2014; between 01.01.2013 and 01.01.2014 all customers connected to the distribution network are eligible for supply via DS.

<sup>78</sup> Default supplier and supplier of last resort in Ukrainian legislation are not defined as such. But, according to the Electricity Law and Rules and Conditions of business activity for electricity supply at regulated tariff № 15/1 of 13.06.1996, adopted by NERC, licensee has no right to refuse to conclude an electricity supply agreement with customer which is located in designated area, and must purchase electricity on the wholesale electricity market of Ukraine to supply electricity to any consumer located in designated area based on electricity supply contract.
### Table 13 Cases in which default supplier or supplier of last resort is applicable

<table>
<thead>
<tr>
<th></th>
<th>Customer non-payment</th>
<th>Customer cannot find a supplier</th>
<th>Supplier goes bankrupt</th>
<th>Customer does not choose a supplier</th>
<th>Expired contract</th>
<th>Other</th>
</tr>
</thead>
<tbody>
<tr>
<td>Albania</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bosnia and Herzegovina</td>
<td>SLR</td>
<td>SLR</td>
<td>DS</td>
<td></td>
<td></td>
<td>DS</td>
</tr>
<tr>
<td>Croatia</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>In Croatia DS is universal service supplier who is applicable only for household. He is SLR for households. SLR is applicable for all non-household customers. In this moment HEP – Operator of distribution system is DS and SLR.</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td></td>
<td></td>
<td>SLR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kosovo*</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Moldova</td>
<td>SLR</td>
<td>SLR</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Montenegro</td>
<td></td>
<td>SLR</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Serbia</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR: Expiry or cancellation of the supplier’s license</td>
</tr>
<tr>
<td>Turkey</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td>SLR</td>
<td></td>
</tr>
<tr>
<td>Ukraine</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>not applicable</td>
</tr>
</tbody>
</table>
In order to calculate the allowed revenue for the provision of universal service some regulators define how the commodity sold by retailers is to be procured. There are several possibilities, such as procurement at power exchange, bilateral contracts, auctions or some combination of the mentioned methods. **In the great majority of the analyzed markets bilateral contracts are used for procurement of energy for universal service provision. The regulatory authorities always have insight in those contracts.** Only in FYR of Macedonia\(^79\), Montenegro and Turkey\(^80\) energy is procured by using a combination of methods\(^81\). In Ukraine, the energy is procured on the wholesale electricity market (single buyer model) as well as by contracts with the producers which are not obliged to sell electricity to the wholesale market.

Finally, the provision of universal service or fulfillment of public service obligation in the sense of implementing **regulation of end-user prices** is in many cases limited in time. In Albania, Croatia, Serbia\(^82\), Turkey and Ukraine the implementation of regulated prices for households and small enterprises has no **time limitation**. In all other examined markets the final deadline for abandoning regulated end-user prices for households is 1\(^{st}\) January 2015 and for small enterprises in some cases even earlier (please see the figure below for details).

---

**Figure 10 Time schedule for abandoning of the regulated price for households and small enterprises\(^83\)**

---

\(^79\) The energy is procured from the electricity generator whose license also includes the obligation on public service provision under prices approved by the regulator as well as from the liberalized market under rules approved also by the regulator (tendering procedure).

\(^80\) 15% power exchange, 80% bilateral contracts, 5% other

\(^81\) In Albania retail public supplier buys electricity from wholesale public supply for tariff customers, only the electricity for covering losses is bought on the market.

\(^82\) On 1st January 2015 HH and SME become eligible for changing suppliers but they may also opt for regulated prices in terms of universal supply (public supply). There is no time limitation in the right of HH and SME to enjoy universal service at regulated prices.

\(^83\) In FYR of Macedonia the deadline for small enterprises is 1\(^{st}\) April 2014.
FINDINGS GAS

Having in mind that Albania, Kosovo* and Montenegro do not have gas markets, this part of the report does not include information on these three markets. Information provided for Bosnia and Herzegovina refers to its entity Republika Srpska only, having in mind that the regulatory practice in the gas sector has been only introduced in this part of the country.  

Gas transmission and distribution

1. Type of regulation

Similar to product prices in all other regulated network industries, gas transmission and distribution tariffs can be determined by using different types of price control mechanisms:

- **Cost plus (or rate-of-return) regulation**, where tariffs are set in a way to cover the system operator’s justified costs and include a rate of return i.e. a return on the capital invested;

- **Revenue or price cap regulation**, where revenues/prices are set in advance for a fixed period of several years ("regulatory period") allowing system operators to keep cost savings they are able to acquire during this period due to, e.g. increase of efficiency in system operation. Typically, yearly tariffs resulting from cap regulation only vary based on the level of inflation corrected by a predetermined percentage rate of efficiency growth;

- **Other mechanisms**, such as yardstick regulation or performance based regulation; these models are, however, less widely spread compared to the previously mentioned mechanisms.

---

84 In the Federation BIH, the competent entity Ministry performs the function of a regulator until the final establishment of an independent regulatory body competent for gas at the level of Federation BIH and/or state level. A gas law does not exist on state level in Bosnia and Herzegovina. Consequently, the competences of the State Regulatory Commission (SERC) and the entity regulator in the Federation BIH (FERK) still exclusively cover the electricity sector only.  

85 CPI-X regulation involves setting a price-path (price-cap regulation) for a utility, allowing for changes in inflation (the CPI factor) and expected efficiency improvements (the “X” factor; These efficiency improvements are separate from the economy-wide efficiency improvements already reflected in the change in the CPI). The “X” factor may incorporate other aspects in addition to the expected improvement in efficiency, such as rewards for improvements in output quality, service levels or demand management actions. CPI-X regulation may also be applied to total required revenue under revenue-cap regulation (Independent Pricing and Regulatory Tribunal (Dennis Mahoney, Cato Jorgensen, Thomas Clay), Incentives for cost saving in CPI-X regimes, July 2011).
In the analyzed markets cost plus, price cap and revenue cap regulation are implemented. Cost plus regulation is normally performed on yearly basis\(^{86}\), while in the case of incentive based regulation the revenues or prices are capped for different periods, namely 3 or 5 years. The figure below provides an overview of the applied tariff regulation models.

Figure 11 Type of implemented regulation in gas transmission and distribution

In cases where the revenue or price cap methodology is implemented (Croatia, FYR of Macedonia, Moldova and Turkey for distribution), revenues are usually fixed for 5 years. Only in Turkey a 3-years revenue cap is implemented for transmission and in Croatia for the first regulatory period (2014-2016) a 3-years- revenue cap is applied, after which also a 5-years-revenue caps will be used.

2. Allowed revenue and accounting guidelines

For all types of tariff regulation allowed revenues need to be determined, i.e. costs allowed to be recovered via the network tariff. Eligible costs include justified and efficient operation and maintenance costs and the capital costs (depreciation and return on assets). Allowed revenues

\(^{86}\) This however does not mean that tariffs are necessarily changed every year, but that the calculation base is one year. Tariffs are changed on the request of regulated company or when regulator concludes that basic parameters for allowed revenue and tariff calculation have been changed.
additionally also include the compensation of network losses as well as a correction factor addressing variations between the forecast and actual values.

In order to facilitate the process of allowed revenue calculation, some regulatory authorities require from regulated companies to prepare and submit separate regulated accounts that can to a certain extent differ from national statutory accounting standards. Such "regulatory accounting rules" (guidelines) should not create an additional burden for regulated companies but help them to understand the process of regulation and increase transparency.

Among the analyzed gas markets, in Bosnia and Herzegovina's entity Republika Srpska, Croatia, Moldova and Ukraine, the regulatory authorities defined separate regulatory accounting guidelines for both transmission and distribution. In more detail:

- In Bosnia and Herzegovina- Republika Srpska the regulatory authority prescribed Uniform Regulatory Chart of Accounts for book-keeping records and financial reports development\(^{87}\);  
- In Croatia a Decision on the Method and Procedure for Keeping Separate Accounting of Energy Undertakings has been adopted by the regulatory authority\(^{88}\);  
- In Moldova the regulator approved a Regulation on accounting system to/at gas sector enterprises\(^{89}\);  
- In Ukraine, separate cost accounting standards are specified in several acts: the Law of Ukraine on natural gas monopolies, the Licensing terms for the pipeline gas transportation and distribution of natural gas, petroleum gas and gas (methane) of coal deposits, The procedure of establishing and reviewing tariffs for transmission, distribution and supply of natural gas, pumping, storage and gas extraction\(^{90}\), The procedure of calculation of tariffs for transmission, distribution, supply, pumping, storage and gas extraction\(^{91}\), The methods for tariff calculation for natural gas transmission and distribution\(^{92}\); Reporting forms: Form 4 NERC-gas.

3. Operating and maintenance costs

Operating and maintenance costs (O&M costs) allow regulated companies to provide and maintain the adequate service level. Regulatory authorities recognize operating and maintenance costs in the allowed revenue but have to differentiate between justified and non-justified costs in order to avoid excessive and unnecessary costs being included in tariffs.

The assessment hereinafter analyses whether regulators apply criteria for recognition of operational expenditures in the allowed revenue defining which costs are considered

\(^{87}\) Published on the web page of the regulator: www.reers.ba.  
\(^{88}\) Official Gazette No. 103/03.  
\(^{89}\) Approved by the decision of the Administrative Board of the National Agency of Energy Regulation No. 76 of 29.12.2002.  
\(^{90}\) All adopted by NERC on 03.04.2013 (No.369).  
\(^{91}\) Adopted by NERC on 28.07.2011 (No. 1384).  
\(^{92}\) Adopted by NERC on 04.09.2002 (No. 984).
justified/non-justified, predefining some costs as controllable and non-controllable\(^93\) and/or predetermining limits for certain costs.

- Only in Georgia and Turkey all operating and maintenance costs from statutory accounting are included in the allowed revenue for gas transmission and distribution.

- The regulators in Bosnia and Herzegovina- Republika Srpska, Croatia, Moldova, FYR of Macedonia, Serbia and Ukraine define certain categories of O&M costs as justified or non-justified, and consider all O&M costs controllable. However, an explicit list of non-justified costs exists only in Croatia, Moldova and Ukraine and typically exclude fines/penalties system operators have to pay to other authorities, sponsorships, doubtful debts, costs for network connections\(^94\) etc.

- The regulators of Bosnia and Herzegovina- Republika Srpska and Serbia defined generally justified cost categories, the relevant methodologies however include also a provision allowing the regulator to consider whether costs are justified or non-justified for every single cost.

- In FYR of Macedonia the regulatory authority defined limits for some costs categories, for example that maintenance costs may not exceed 20% of annual depreciation costs or that gross salaries per employee may be recognized only to a level 40% higher than average gross salary in the country.

A graphical overview of the implemented approaches for recognition of operating and maintenance costs in the allowed revenue is presented below.

\textit{Figure 12 Recognition of O&M costs in the allowed revenue for gas transmission and distribution}

\(^93\) Non- controllable costs, if recognized as such, are normally automatically included in the allowed revenue.

\(^94\) Costs of network connection are to be covered by a separate connection charge. Not applicable in Ukraine.
In case of incentive based regulation an **efficiency factor** is applied i.e. “the regulator sets prices not on the basis of the company’s actually incurred costs, but rather on a level of cost that the regulator considers efficient. The difference between actual costs and the regulatory estimation of efficient costs is reflected in the X factor. The X factor applies for a given number of years (the regulatory period) and determines the annual change in prices in such a way that prices move in line with the anticipated efficiency improvements. Through the X factor, consumers directly participate in the expected cost reductions in the form of lower price. On the other hand, the company will also benefit as long as it manages to reduce costs in excess of the X factor. The residual cost savings can then be retained in the form of higher profits.” As mentioned above, incentive base regulation for gas transmission and distribution is applied only in Croatia, FYR of Macedonia, Moldova and Turkey. The following efficiency factors apply:

- 0% for the first regulatory period in Croatia (for the following periods it will be determined yearly and individually i.e. for each company separately)
- 2% in Moldova, sector based

However the methodologies for X factor determination still do not follow the academically recognized benchmarking models, such as parametric and non-parametric tests but the individually developed procedures of relevant regulatory authorities. In Moldova the regulator takes into consideration efficiency improvements in the previous periods as well as the investments contributing to efficiency increase. The exception is Turkey, where DEA benchmarking method is implemented and the resulting X factor is applied to total level of OPEX.

### 4. Return on assets

In order to recognize owner’s investment in the regulated company, the allowed revenue always includes **return on assets**. Return on assets is measured by multiplying the rate of return with the value of the regulatory asset base.

The **regulatory asset base (RAB)** aggregates net asset values of fixed assets and sometimes current assets (also called working capital), excluding capital contributions, sometimes also assets under construction. Asset valuation is an important element of RAB determination. Some regulatory authorities therefore prefer using their own asset valuation methodology. In any case.

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95 *Efficiency factor’s determination (X factor)*, Issue paper of ERRA Tariff/Pricing Committee, prepared by KEMA International B.V. in August 2006, please see more on X Factor determination on [http://www.erranet.org/Library/ERRA_Issue_Papers#2](http://www.erranet.org/Library/ERRA_Issue_Papers#2).

96 Revenue cap type of regulation applied in FYR of Macedonia for gas transmission is based on setting the 5-years-revenue stream allowing increase in revenues coming from inflation rate and smoothing factor i.e. factor that distributes differences between planned revenues of a company and those approved by the regulator over the regulatory period. Increase in efficiency is currently not envisaged. However, only for the activity “operation of transmission system” the allowed revenue formula envisages efficiency factor, but so far it has not been applied.

97 Assets not yet commissioned, i.e. not yet in use.
all regulatory authorities have a discretionary right to define and decide which assets belong to the regulated business and, to avoid sunk investments, which investments are justified.

The results of the questionnaire related to RAB structure and asset valuation are presented below. Here it has to be highlighted that currently the process of allowed revenue determination in Ukraine does not apply the concept of RAB related calculation of return. Calculation of allowed revenue for transmission and distribution is done by taking into account reasonable costs and planned profit (not determined as rate of return on capital employed). Therefore, the information on Ukraine in this and the following chapter will be only selective, as appropriate. When providing information on RAB, this consequently does not include Ukraine.

<table>
<thead>
<tr>
<th></th>
<th>Has the regulator right to re-evaluate assets if deems necessary?</th>
<th>Have assets been re-evaluated in the process of tariff regulation?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina-RS</td>
<td>yes</td>
<td>yes</td>
</tr>
<tr>
<td>Croatia</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>yes</td>
<td>no</td>
</tr>
<tr>
<td>Georgia</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Moldova</td>
<td>no</td>
<td>yes&lt;sup&gt;98&lt;/sup&gt;</td>
</tr>
<tr>
<td>Serbia</td>
<td>no</td>
<td>no</td>
</tr>
<tr>
<td>Turkey</td>
<td>no for transmission, yes for distribution</td>
<td>no for transmission, yes for distribution</td>
</tr>
<tr>
<td>Ukraine</td>
<td>no</td>
<td>no</td>
</tr>
</tbody>
</table>

With the exception of Bosnia and Herzegovina- Republika Srpska, FYR of Macedonia and Turkey for distribution the regulatory authorities of the analyzed markets do not have the legal power to re-evaluate assets of regulated companies.

In all investigated markets the regulatory authorities approve investment plans ex-ante and monitor their implementation. The exception is Bosnia and Herzegovina-Repulika Srpska where the entity regulator only monitors the implementation of investment plans.

The realization of investment plans influences the value of RAB only to the extent the allowed revenue includes some investments in advance, i.e. before commissioning of assets. In the

<sup>98</sup> The assets of gas transmission and distribution regulated entities were re-evaluated in 2008 year (the previous regulatory period) using historic costs methodology. According to current tariff methodology it is not allowed to reevaluate assets for the full period of tariff methodology validity (the current regulatory period is 2010-2014) and the value of these assets will be constant, equal to balance value on 31.12.2008.
analyzed gas markets, assets under construction are included in the RAB only in Bosnia and Herzegovina-Republika Srpska, FYR of Macedonia and Serbia. In FYR of Macedonia these assets are included ex-ante, as a tool for incentivizing investments, while in Bosnia and Herzegovina-Republika Srpska and Serbia only the part of an asset under construction that is planned be commissioned in the regulatory period is included in the RAB\(^99\).

Another very important element of RAB calculation are capital contributions, i.e. grants from e.g. the government or an international institution and direct payments by asset users, in case of networks typically connection assets. Normally the assets financed from such contributions are excluded from the RAB, in order to avoid return on assets that are not the result of the regulated company’s investment. In some cases however, depreciation of these assets is allowed with a view to enable replacing of the assets in the future.

In all analyzed Energy Community markets the capital contributions are always excluded from the RAB by the regulators.

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**Figure 13 Treatment of depreciation of capital contributions in gas transmission and distribution**

![Pie chart showing treatment of capital contributions](image)

Other elements considered for calculating the RAB are intangible assets and working capital. **Intangible assets** are long-term resources of the company, but have no physical existence. They derive their value from intellectual or legal rights and from the value they add to the other assets\(^100\). When determining the RAB some regulatory authorities decide not to include the value

\(^99\) Afterwards ex-post corrected if the investment was not commissioned.

\(^100\) Examples are patents, copyrights, goodwill.
of these assets. **Working capital**, defined as difference between company’s current assets\(^{101}\) and current liabilities\(^{102}\) is also sometimes excluded from RAB.

The graphs below show the recognition of intangible assets and working capital in the RABs of investigated markets.

**Figure 14** *Treatment of intangible assets in RAB for gas transmission and distribution*

**Figure 15** *Treatment of working capital in RAB for gas transmission and distribution*

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\(^{101}\) Assets that will be turned into cash within a year.

\(^{102}\) Liabilities that will be repaid within a year.
From the graphs above it can be concluded that the regulatory authorities of the analyzed markets treat values of intangible assets and working capital when calculating the RAB differently. Both approaches however may be justified.

Finally, once the RAB has been calculated for the regulatory period, it may be adjusted on yearly basis in case of incentive based regulation - as shown above, this is the case in Croatia, FYR of Macedonia, Moldova and Turkey. The table below provides explanations on the chosen approaches chosen by regulatory authorities of these markets.

Table 15 Treatment of RAB during the regulatory period - gas transmission and distribution

<table>
<thead>
<tr>
<th></th>
<th>Treatment of RAB during the regulatory period</th>
</tr>
</thead>
<tbody>
<tr>
<td>Croatia</td>
<td>RAB values are set for all regulatory years prior to the beginning of the regulatory period and are unchanged during the regulatory period. According to methodology, there is a possibility for exceptional revision of allowed revenues (which includes RAB values) for the current regulatory period at the operator’s request or according to the assessment of HERA. Exceptional revision of RAB is performed due to unexpected changes in the market that have significant impact on the conditions of performing energy activity of gas transmission, and that TSO/DSO could not anticipate, prevent, eliminate or avoid.</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>RAB is determined for every year of the regulatory period and is not change before the end of the whole regulatory period.</td>
</tr>
<tr>
<td>Moldova</td>
<td>Investments commissioned during the previous year always increase the RAB in the following year.</td>
</tr>
</tbody>
</table>

While the purpose of incentive based regulation, in principle, is to allow revenues remaining unchanged during the regulatory period and therefore allowing regulated utilities to consume the benefits of cost reductions during that time, the approach of Moldova’s regulator has to be assessed very positively against incentivizing investments.

5. Rate of return

Regulated service providers have interest to invest only if the recognized return allows them to cover costs of equity and debt finance needed for the realization of the envisaged projects. The rate of return regulators determine has to take into consideration the credit conditions available to particular regulated companies but also to comparable industries since the utilities in the energy sector do not only compete among themselves for financing sources. Furthermore, the rate of return has to enable investors to cover their finance (equity) requirements and secures at least
the risk-free rate of interest plus a risk premium reflecting risks specific for the particular sector of energy industry.

The **Weighted Average Cost of Capital** (WACC) is a commonly used method for calculation of the rate of return in regulated energy business. As the name suggests, it reflects weighted average of the cost of each individual component of the capital structure\(^\text{103}\). WACC may be determined as pre-tax or post-tax figure. Pre-tax WACC allows not only coverage of finance cost but also tax coverage. Post-tax WACC assumes that the utility already paid the tax. For the estimation of costs of equity usually the Capital Assets Pricing Model is applied\(^\text{104}\).

The regulatory authorities of the analyzed markets reported figures for real pre-tax WACC for gas transmission and distribution, including the relevant components for its calculation and they are presented in the table below. As mentioned in the previous chapter, Ukraine does not implement the concept of RAB and return on assets; consequently there will be no related information on Ukraine in this chapter.

<table>
<thead>
<tr>
<th></th>
<th>WACC (real, pre-tax)</th>
<th>Gearing (debt/(debt+equity))</th>
<th>Return on equity</th>
<th>Return on debt</th>
<th>Risk free rate</th>
<th>Beta coefficient</th>
<th>Market return</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina -RS</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>T</td>
<td>1,80</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>D</td>
<td>0 and 6 for two DSOs</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Croatia</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>T</td>
<td>7,32 (nominal,pre-tax)</td>
<td>50</td>
<td>8,63</td>
<td>3,85</td>
<td>5,5(^\text{105})</td>
<td>54(^\text{106})</td>
<td>11,30(^\text{107})</td>
</tr>
<tr>
<td>D</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
<td>-</td>
</tr>
</tbody>
</table>

\(^\text{103}\) Weight is the share of capital component.

\(^\text{104}\) For more details on WACC calculation please see e.g. [http://books.google.at/books?id=cGqmeynpZ48C&printsec=frontcover&source=gbs_ge_summary_r&redir_esc=y#v=onepage&q&f=false](http://books.google.at/books?id=cGqmeynpZ48C&printsec=frontcover&source=gbs_ge_summary_r&redir_esc=y#v=onepage&q&f=false) or [http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Jenkinson_Regulation_and_the.pdf](http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/Jenkinson_Regulation_and_the.pdf)

\(^\text{105}\) The risk free rate is determined on the basis of the nominal interest rate of latest domestic or international ten year bond issued by the Republic of Croatia.

\(^\text{106}\) The beta coefficient is determined on the basis of a comparative analysis of the gas system operators’ beta coefficients applied in the regulatory mechanisms of European countries.

\(^\text{107}\) Market return is calculated as the sum of the risk-free rate and the market risk premium, which is determined based on the expected rate of return on the diversified market portfolio in the Republic of Croatia.

\(^\text{108}\) The procedure of tariff approval is ongoing and the figures are currently not available.
WACC (real, pre-tax) | Gearing (debt/(debt+equity)) | Return on equity | Return on debt | Risk free rate | Beta coefficient | Market return
---|---|---|---|---|---|---
FYR of Macedonia | T | 9,39 | 1,25 | 8,53 | 2.33 | 4.68 | 1 | 8.53
| D | - | - | - | - | - | - | -
Georgia | T | 8 | - | - | - | - | - | -
| D | 8 | - | - | - | - | - | -
Moldova | T & D | 12,2305 | 35 | 12,232 | 9,13 | 1,8 | 70 | 5,26
Serbia | T & D | 7,50 | 60 | 10 | 5,10 | 4.8 | 0.83 | 6.2
Turkey | T | - | - | - | - | - | - | -
| D | 11,83 | - | - | - | - | - | -

### 6. Depreciation

Depreciation is an allocation of asset costs to the accounting period in which the asset provides benefits to the company. The purpose of calculating depreciation is building up funds for the replacement of assets. There are a number of approaches for calculating depreciation, but the most widely used is straight-line/linear depreciation where the asset is written off every year with the same amount. In order to quickly write off an asset and therefore return the invested capital

109 Return on Government bonds.
110 Having in mind that the distribution system in FYR of Macedonia is still at the low level of development, the relevant tariff methodologies are not fully implemented.
111 Based on the treasury bonds risk free rates of USA with maturity of more than 10 years according to statistics published on Bloomberg.
112 Based on data published in the statistical summary of DAMODARAN, in the part “Betas of industry”, natural gas enterprises in the developing countries(http://pages.stern.nyu.edu/~ADAMODAR/New_Home_Page/datafile/Betas.html).
113 All figures represent the average of minimum and maximum values used for calculation.
114 Nominal rate of long term Governmental bonds decreased by percentage of inflation.
115 International benchmark, as energy utilities in the SAD.
116 Calculated as the sum of risk-free rate in other countries, market premium in other countries and country credit rating of Serbia minus country credit rating in other countries.
sooner, some regulators use accelerated depreciation where yearly deductions are greater in the first years of asset use. It has to be noted that depreciation used for regulatory tariff setting can deviate from national tax law depreciation rules. The regulatory authorities of the analyzed markets use mostly straight-line depreciation and there is usually no differentiation between assets acquired before and during the regulatory period. In some cases (Croatia, Serbia and Turkey) the regulators determine the asset lives that are used in the allowed revenue calculation. The details on the depreciation methods for gas transmission and distribution are shown in the table below. The information on asset lives in straight-line depreciation explains how quickly the asset costs are actually recovered.

Table 17 Depreciation of gas transmission and distribution assets

<table>
<thead>
<tr>
<th></th>
<th>Depreciation method applied</th>
<th>Does the regulator define asset lives for the regulatory purposes?</th>
<th>Asset lives (in years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina-RS</td>
<td>Transmission: one company applies straight-line method and another one functional method for pipelines and MRS and straight-line for other assets Distribution: straight-line</td>
<td>no</td>
<td>33 years for pipelines and compressor stations</td>
</tr>
<tr>
<td>Croatia</td>
<td>Straight-line; other methods possible</td>
<td>yes</td>
<td>Minimally 35 years for pipelines, compressor stations and buildings</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Straight-line</td>
<td>no</td>
<td>Pipelines 40, compressor stations 20</td>
</tr>
<tr>
<td>Georgia</td>
<td>Straight-line, tax norm method (increased norms) or doubled method for existing assets and for new assets according to the usage period</td>
<td>no</td>
<td>Plastic pipelines 50, metal pipelines 40, compressor stations 40</td>
</tr>
<tr>
<td>Country</td>
<td>Depreciation method applied</td>
<td>Does the regulator define asset lives for the regulatory purposes?</td>
<td>Asset lives (in years)</td>
</tr>
<tr>
<td>---------</td>
<td>-----------------------------</td>
<td>---------------------------------------------------------------</td>
<td>------------------------</td>
</tr>
<tr>
<td>Moldova</td>
<td>Straight-line</td>
<td>no</td>
<td>Pipeline 25-35, compressor stations 20-22, superflow measurement equipment 15-20, distribution and metering stations 20-23</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Pipelines 20-25, compressor stations 20-25, superflow measurement equipment 9, distribution and metering stations 20-25</td>
</tr>
<tr>
<td>Serbia</td>
<td>Straight-line</td>
<td>yes</td>
<td>Pipelines 33, compressor stations 8, gas stations 13</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Pipelines 40, metering devices 12</td>
</tr>
<tr>
<td>Turkey</td>
<td>Straight-line</td>
<td>yes</td>
<td>-</td>
</tr>
<tr>
<td>Ukraine</td>
<td>Straight line</td>
<td>no</td>
<td>Pipelines (steel) over 40-50 years, buildings over 20</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Pipelines (steel) over 40-50, pipelines plastic over 50, buildings over 20</td>
</tr>
</tbody>
</table>

Croatia introduced an optional incentive regulation model, i.e. so-called “model of the regulatory account”. This is optional model for a DSO who plans to invest in new (“greenfield”) projects or in significant increase of the existing distribution system. In this case, the period for which a regulatory account is established cannot be less than two regulatory periods and cannot exceed than the period for which the relevant DSO has signed a concession agreement. In order to be qualified for establishing the regulatory account according to this methodology, the relevant DSO must meet certain preconditions. For calculation of the planned depreciation of regulated assets in the period of the regulatory account it is possible to apply a progressive depreciation method instead of linear depreciation. In essence, this model allows investments costs for "greenfield" projects to be depreciated over a longer period than the usual regulatory period; this avoids high initial tariffs that would result from depreciating the investment within the usual regulatory period and would discourage customers to use the newly established network. The benefits of this model in particular materialize in the light of promotion of gasification.
7. Losses

During the transport of gas through a gas network, energy is lost due to physical and non-physical reasons. Therefore there are 2 types of network gas losses:

- **Technical losses** due to gas leaks
- **Non-technical losses** i.e. consumed energy that cannot be billed to an end user. Reasons for these losses include: imprecise or incorrect readings and fraud.

Network operators are responsible for the compensation of losses. They purchase appropriate quantities of energy. The costs of network losses are mostly controllable in a long-run, but not in a short-run (e.g. during the regulatory period). The way they are included in the allowed revenue (if included at all) can be different, e.g. as part of operating costs\(^\text{117}\) or as separate allowed revenue category\(^\text{118}\). In any case, the regulator has to ensure network efficiency, not only by recognizing a certain amount of losses, but also by stimulating network operators to reduce them.

The table below provides information on the **definition and criteria applied by the regulators of the analyzed markets for recognizing losses in the allowed revenue for gas transmission and distribution** and provides figures for **allowed losses** and applicable prices that are used for defining the allowed cost.

The results of the questionnaire are presented in the table below.

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\(^{117}\) In case of incentive based regulation the applied efficiency factor then also relates to costs of losses.

\(^{118}\) The maximum value is set for the amount of losses as well as the rule applicable for purchase price.
<table>
<thead>
<tr>
<th></th>
<th>Costs related to network losses recognized in the allowed revenue for transmission/distribution?</th>
<th>Is there a separate definition of technical and non-technical losses?</th>
<th>Criteria for recognition of losses in the AR</th>
<th>How is price for allowed losses determined?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina-RS</td>
<td>yes</td>
<td>no</td>
<td>The decision on allowed losses is made based on analysis of the actual losses, condition of the network and benchmarking analysis</td>
<td>Procurement price of gas</td>
</tr>
<tr>
<td>Croatia</td>
<td>yes</td>
<td>No, the allowed losses include operating losses and differences in measurement</td>
<td>The level of allowed losses is fixed to 0.3%</td>
<td>The TSO purchases gas for losses at a price that is not regulated. The allowed reasonable price for covering allowed losses HERA is reasonable average unit price of gas that is the result of analysis of market data i.e. prices collected from all gas suppliers and retailers. The allowed reasonable price for the first regulatory period is the average sales price of natural gas for commercial customers, with annual gas consumption of more than 50 GWh in the retail market for the 1Q 2013, reduced by the average fee for use of the transmission system for end customers connected to the transmission system</td>
</tr>
<tr>
<td>Austria</td>
<td>yes</td>
<td>No, the allowed losses include both technical and commercial losses</td>
<td>The level of allowed losses is fixed to 3%, but the regulator may allow also bigger amount taking into consideration the specific characteristics of the DSO and if the relevant DSO submits the plan for reduction of losses.</td>
<td>The DSO purchases gas for losses at a price that is not regulated. HERA will define the allowed reasonable price for covering allowed losses through analysis of tariff applications (expected in autumn 2013)</td>
</tr>
<tr>
<td>Country</td>
<td>T&amp;D</td>
<td>Costs related to network losses recognized in the allowed revenue for transmission/distribution?</td>
<td>Is there a separate definition of technical and non-technical losses?</td>
<td>Criteria for recognition of losses in the AR</td>
</tr>
<tr>
<td>------------------</td>
<td>-----</td>
<td>------------------------------------------------------------------------------------------------</td>
<td>------------------------------------------------------------------</td>
<td>---------------------------------------------</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>T&amp;D</td>
<td>yes</td>
<td>No, only technical losses recognized</td>
<td>The quantities of natural gas for covering of the allowed technical losses are up to 0.5% of the total entry quantity of natural gas for the TSO and up to 0.7% of the total entry quantity of natural gas in the DSO.</td>
</tr>
<tr>
<td>Georgia</td>
<td>T&amp;D</td>
<td>yes</td>
<td>Only normative technical losses recognized; commercial costs not recognized</td>
<td>Only normative technical losses recognized</td>
</tr>
</tbody>
</table>
| Moldova          | T&D | yes                                                                                           | There is a definition\(^{119}\) for normative technical losses    | Only normative technical losses recognized | TSO: Sum of the purchase price of imported gas and customs duty  
DSO: purchase price at which suppliers buy gas |
| Serbia           | T&D | yes                                                                                           | no                                                               | The decision on allowed losses is made based on analysis of the actual losses from the past 3 years (increasing trend is not allowed), condition of the network and benchmarking analysis | Weighted average purchase gas price including all valid affiliated costs for purchase |

\(^{119}\) Based on the normative act determining planning parameters (transportation regime and planed repair works, planed works for operation and maintenance of transmission networks), technological consumption and emissions of natural gas recognized in the allowed revenue are determined for the next year. At the end of the year the level of losses is adjusted based on realized parameters (actual transportation regime and actual repair works, works for operation and maintenance of transmission networks. For distribution the planning parameters are: forecast network length, the number of consumers, work regime and planed repair works, planed works for operation and maintenance of distribution networks.
<table>
<thead>
<tr>
<th>Country</th>
<th>Costs related to network losses recognized in the allowed revenue for transmission/distribution?</th>
<th>Is there a separate definition of technical and non-technical losses?</th>
<th>Criteria for recognition of losses in the AR</th>
<th>How is price for allowed losses determined?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ukraine</td>
<td>yes</td>
<td>There is a definition for operational technological losses and normative losses[^100], commercial costs not recognized</td>
<td>Only operational technological, normative losses of gas and gas for own needs recognized</td>
<td>Gas price set for industrial customers and other economic entities</td>
</tr>
<tr>
<td>D</td>
<td>yes</td>
<td>There is a definition for operational technological losses and normative losses; commercial costs not recognized</td>
<td>Only operational technological, normative losses of gas and gas for own needs recognized</td>
<td>Gas price set for industrial customers and other economic entities</td>
</tr>
</tbody>
</table>

[^100]: Operational technological and normative losses of gas are losses of natural gas associated with the technological process of natural gas transmission and distribution.
The costs related to network losses are recognized in the allowed revenue for transmission and distribution in all analyzed markets.

The definitions of transmission and distribution losses do not distinguish between technical and non-technical (commercial) losses i.e. they simply calculate the difference between input and output of gas. In Georgia and Moldova there is even a definition of normative (standardized) technical network losses that per default exclude any non-technical losses. In Ukraine there is a definition of operational technological and normative losses of gas that also per default exclude any non-technical losses. In those cases where more than normative technical losses are recognized in the allowed revenue, the criteria used mainly rely on historical data on losses and benchmarking with other similar networks.

When calculating the level of losses-related costs in the allowed revenue, regulators use different supply or purchase gas prices - including affiliated purchase costs and transmission charges for distribution losses.

In Ukraine when calculating the level of losses – related to volumes of operational technological losses and normative (standardized) losses of gas for distribution in the allowed revenue, regulator uses volumes of operational technological losses and normative (standardized) losses of gas, purchase gas prices and tariff for transmission within the distribution company territory.

Currently allowed percentages of losses in transmission and distribution network are presented in the figures below.

Figure 16 Allowed levels of losses in the gas transmission networks (in %)
8. Deducted revenues

Transmission and distribution system operators may earn revenues from non-regulated activities, but performed by using the same assets already included in RAB, e.g. revenues from selling short-term capacities or from reconnection. In order to avoid double earnings from the same assets, the regulators often deduct such non-regulated revenues from the regulated allowed revenue.

The figure below explains which regulatory authorities deduct some non-regulated revenues from the transmission and distribution allowed revenue.

Figure 18 Deduction of non-regulated revenues from the regulated allowed revenue in gas transmission and distribution
Where the non-regulated revenues are deducted from the calculated allowed revenue for gas transmission, the following mechanisms apply:

- **Croatia**: revenues from connection fees and increased connection capacity, revenues from non-standard services and other operating revenues that are not related to the main activity of the TSO
- **Georgia**: third countries transit revenues
- **Serbia**: revenues incurred by selling contracted monthly and daily firm and interruptible capacities, revenues collected by balancing activities\(^{121}\), revenues from activation of own goods and outputs, revenues collected by selling regulated assets, revenues arising from contracted capacity overrun, revenues arising from issuing approvals with conditions for works in protected area around the pipeline, revenues arising from compensations\(^{122}\), revenues incurred by suspension of natural gas delivery, revenues in terms of contracted backhaul capacity and other revenues.

For gas distribution, the following revenues are deducted from the allowed revenue:

- **Croatia**: revenues from connection fees and increased connection capacity, revenues from non-standard services and other operating revenues that are not related to the main activity of the DSO but based on which there are items registered in OPEX, and that are not excluded from the calculation of depreciation and the value of regulated assets
- **Georgia**: third countries pass-through revenues
- **Serbia**: revenues from activation of own goods and outputs, revenues collected by selling regulated assets, revenues arising from issuing approvals with conditions for works in protected area around the pipeline, revenues arising from compensations, revenues incurred by suspension of natural gas delivery and other revenues.

9. **Quantities**

Once the allowed revenue is calculated, the quantity of sold products needs to be established for the determination of the actual tariff. Overestimated or underestimated quantities may substantially influence the level of tariffs. This is the reason why most of the regulators revise and finally approve the level of quantities to be used for determination of tariffs. In order to be transparent when calculating or approving tariffs, regulators should establish and publish criteria for revising or approving these quantities.

The table below provides an overview of the criteria implemented for revision and determination of quantities used for calculation of transmission and distribution tariffs.

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\(^{121}\) Having in mind that the TSO also performs the activities of market operation and in order to provide that it remains cost-neutral regarding costs and revenues from balancing (done on market), the regulator includes planned balancing related costs as part of operating costs in the allowed revenue, but also deducts the same amount as part of other revenues. Any differences between planned and realized balancing costs/revenues are then added or deducted from the allowed revenue of the next year, as part of correction element.

\(^{122}\) E.g. compensation from insurance company for damage to the regulated assets
Table 19 *Sources of quantities used for gas transmission and distribution tariff calculation*

<table>
<thead>
<tr>
<th>Country</th>
<th>Sources of quantities used for transmission and distribution tariff calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina</td>
<td>Analysis of the quantities in the previous year and planned quantities</td>
</tr>
<tr>
<td>Croatia</td>
<td>Planned quantities proposed by TSO/DSO, subject to HERA’s analysis</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Data on planned quantities submitted by TSO/DSO, energy balance, analysis of gas market</td>
</tr>
<tr>
<td>Georgia</td>
<td>Energy balance, previous year actual data</td>
</tr>
<tr>
<td>Moldova</td>
<td>Difference between contracted volumes and normative losses (incl. own gas consumption)</td>
</tr>
<tr>
<td>Serbia</td>
<td>Planned quantities proposed by TSO/DSO, subject to AERS’ analysis</td>
</tr>
<tr>
<td>Ukraine</td>
<td>By taking into consideration actual quantities including the dynamics and projected changes in the planning period, based on contracts with customers</td>
</tr>
</tbody>
</table>

From the information presented in the table above it can be concluded that in the majority of cases regulators prefer having a concrete and provable source of data for quantities used for tariff calculation, such as energy balance or concluded contracts. However, in most of the markets the regulators also have the right to change the amounts of volume taken over from energy balances or other sources, for the purpose of tariff calculation. The exception is Moldova, where the regulator uses quantities from the contracts for calculating tariffs and these quantities are then revised in the scope of correction of the allowed revenue for the next year (see chapter 10 on correction).

**10. Correction**

After expiry of the regulatory period regulators have the opportunity to calculate the difference between the allowed and actually earned revenue. These two values are always different due to the difference between planned and actual quantities, but also because of different planned and realized costs. The amount over over/under-recovery is then to be compensated in the next regulatory period.

The methodologies for the calculation of transmission and distribution allowed revenues and tariffs in the analyzed markets envisage calculation of correction factor based on both realized quantities and costs. More details on the calculation of correction is provided by the regulatory authorities of:
In **Croatia** determining the differences between the revised allowed revenue and realized revenue for each year of the preceding regulatory period is carried out in the year following the last year of the regulatory period, i.e. in the first year of the next regulatory period and according to the following procedure:

1. Net present value of the revised allowed revenue for the regulatory period, reduced to a value from the beginning of the first year of the regulatory period is calculated.

2. Net present value of the realized revenue in the regulatory period, reduced to a value from the beginning of the first year of the regulatory period is calculated.

3. The difference between two net present values is divided on four equal parts (due to four years that remain in the next regulatory period)

4. The future value of the each of the four parts is calculated using WACC as discount rate and is added to the calculation of allowed revenue for the corresponding year of the current regulatory period.

In **Serbia** the correction element is the difference between the actual revenue and actual reasonable costs (evaluated by the regulator) in the previous year and this amount of money will be included in the next regulatory period (correction element can be positive or negative).

In **Moldova** the correction is determined as difference between the plan parameters for determining the tariffs and the real register in previous regulatory period. The following elements are yearly revised: procurement price of natural gas, exchange rate of national currency, volumes of transported gas, pass-through costs, adjustment indices of basic costs, profit for the investment plan, and difference between the losses in the transmission network determined at the beginning and at the end of the period.

In **Ukraine** the regulator may review the tariffs if:

- volumes of service (distribution and supply) change in projected period in comparison to volumes considered when calculating the relative rate of more than 5%;

- changes in costs specified in structure of established tariff occurred for reasons beyond the control of the entity and it leads to changes in established tariff level for more than 5%;

- changes in costs specified in the tariff structure, due to higher prices for fuel, raw materials, services, increased labor costs due to changes in legally defined minimum wage relative to taken into account when calculating the rate by more than 5%.

**Regulation of gas supply**

According to the Energy Community *acquis communautaire* Contracting Parties may impose so-called “public service obligations” on energy companies which may be related, among other, to the **price of supply**. Such obligations need to be *clearly defined, transparent, non-discriminatory, verifiable and shall*
guarantee equality of access for electricity undertakings to consumers\textsuperscript{123}. Against this background, in many countries regulated end-user prices for both households and non-household customers still exist\textsuperscript{124}. It has to be noted that, in case regulated energy prices are set at levels that do not allow recovery of costs, they tend to establish a barrier for the development of competition and effective market opening.

When regulating end-user prices, several components are added to the network charges:

- commodity price i.e. cost of providing electricity,
- supply service costs,
- taxes, levies, regulatory fees, charge for market operator’s services, support for renewables etc.

Under certain circumstances final electricity prices also include components such as bad debts or non-collection rate.

The table below explains how these elements are included in the regulated electricity end-user prices. Please note that the costs of transmission and distribution charged through end-user electricity price by the supplier are then transferred to the operators of transmission and distribution system, in line with applicable tariff systems.

Table 20 Structure of allowed revenue for gas supply

<table>
<thead>
<tr>
<th>Country</th>
<th>Structure of allowed revenue for gas supply</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina - RS</td>
<td>MAR = costs of gas purchase + transmission costs+ distribution costs+ supply service costs</td>
</tr>
<tr>
<td>Croatia\textsuperscript{125}</td>
<td>MAR = gas procurement cost (price set by Gov. decision until 31 March 2014) + transmission costs (average transmission price related to entry capacity proposed by wholesale supplier and with positive opinion by HERA added to procurement cost; exit cost submitted by supplier) + distribution costs + supply service costs</td>
</tr>
</tbody>
</table>

\textsuperscript{123} Art. 3(2) of the Electricity Directive. For the electricity sector the acquis foresees public service obligations in particular in the context of so called “universal service obligations”: Art.3(3) of the Electricity Directive all household customers and small enterprises, as defined by the acquis, are entitled to enjoy universal service, i.e. is the right to be supplied with electricity of a specified quality within their territory at reasonable, easily and clearly comparable, transparent and non-discriminatory prices. A related provision does not exist in the gas acquis.


\textsuperscript{125} The new methodology for setting allowed revenue for regulated gas supply is under preparation. The formula presented in the table refers to the current practice.
### Structure of allowed revenue for gas supply

<table>
<thead>
<tr>
<th>Country</th>
<th>Formula</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>FYR of Macedonia</td>
<td>( ABB_t = Ot + Dt + RAt )</td>
<td>Where: ( ABB_t ) - Allowed revenue for gas supply company in period ( t ); ( Ot ) - Operating and maintenance costs in period ( t ); ( Dt ) - Depreciation in period ( t ); ( RAt ) - Return on regulated assets in period ( t ).</td>
</tr>
<tr>
<td>Moldova</td>
<td>( MAR_t = \text{costs of gas purchase} + \text{transmission costs} + \text{distribution costs} + \text{supply service costs} )</td>
<td></td>
</tr>
<tr>
<td>Serbia</td>
<td>( MAR_t = OPEX_t + Dt + NGPt + DUoS_t + ARCt + CF_t )</td>
<td>Where: ( t ) = regulatory period, ( OPEX_t ) = operating expenditure in period ( t ), ( Dt ) = depreciation costs in period ( t ), ( NGPt ) = costs of natural gas procurement from wholesale supplier including also transmission use of system charge, in period ( t ), ( DUoS_t ) = distribution use of system charges in period ( t ), ( ARCt ) = charge associated with accounts receivable collection risk (i.e. non-collection rate) in period ( t ), ( CF_t ) = correction factor in period ( t ).</td>
</tr>
<tr>
<td>Ukraine</td>
<td>( НД = B + П ), where: ( B ) - is projected operating expenses (material costs, labor costs, payroll charges, depreciation, other expenses); ( П ) - is the planned profit.</td>
<td></td>
</tr>
</tbody>
</table>

In case the price of commodity changes, this influences the cost of providing that commodity to the customers by the suppliers. If supply is regulated, the regulatory authority has to define a mechanism to take these changes into account when determining the end-user prices. This mechanism should describe the cases, in which change of commodity prices will result in a change of the final price as well as whether related costs are treated as pass-through cost\(^{126}\) or some limitation of cost level is introduced.

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\(^{126}\) Whole amount of cost change will be carried over to the customers.
<table>
<thead>
<tr>
<th>Country</th>
<th>Treatment of change in commodity prices in the final price regulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina-RS</td>
<td>If during the regulatory period the procurement price of gas is changed by more than 5%, the supplier may change its regulated price by using the following formula:  [ C_1 = C_0 + (Cg_1 - Cg_0) ]  where:  ( C_1 ) – new price,  ( C_0 ) – currently applicable price,  ( Cg_1 ) – new average gas procurement price  ( Cg_0 ) – average procurement price used for the calculation of currently applicable supply price.</td>
</tr>
<tr>
<td>Croatia</td>
<td>There is no automatic mechanism, the final prices are changed by request of energy subject.</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>The price is set on a monthly basis upon a request of the supplier of tariff consumers connected to the transmission system. In the process of calculation of monthly prices of natural gas the changes in commodity prices are treated accordingly. Monthly retail price of natural gas is set in the following way  [ \text{Monthly retail price of natural gas} = \text{Procurement price (Invoice price + Additional costs such as custom duties, bank provision, bank guarantee, wholesale trade margin, exchange rate differences and charges for higher quality of natural gas) + Transmission tariff + Supply Price} ]</td>
</tr>
<tr>
<td>Moldova</td>
<td>The change in commodity price is treated as pass-through cost and the final price is changed if this commodity-related cost influences the total level of allowed costs by more than 5%. The gas procurement cost is determined according to the formula:  [ \text{CGP} = \sum \text{VGP}_i \times \text{PG}_i \times \text{CV} + \text{TV} ]  where:  ( \text{CGP} ) – the cost of natural gas procurement by JSC “Moldovagaz” during a year;  ( \text{VGP}_i ) – the natural gas volume procured by JSC “Moldovagaz” from the supplier during a year;  ( \text{PG}_i ) – the natural gas procurement price in the currency indicated in the natural gas procurement contract from the supplier during a year;  ( \text{CV} ) - average exchange rate of the national currency to the natural gas purchase currency  ( \text{TV} ) – customs duties paid according to the law.</td>
</tr>
<tr>
<td>Serbia</td>
<td>no automatic mechanism, but suppliers are obliged to submit to the regulator price proposals after more than 3% change in gas purchase price.</td>
</tr>
<tr>
<td>Ukraine</td>
<td>Retail price of natural gas (end user price of gas) for households is based on the weighted average price of gas as a commodity of domestic producers, on National Joint Stock Company &quot;Naftogaz of Ukraine”s expenses associated with the purchase of natural gas and its sale to the households, on tariffs for transmission, distribution and supply of natural gas and on current taxes and fees. For industrial customers end user price of natural gas include the marginal price rate for natural gas, which is based on the price of imported natural gas tariffs for transmission, distribution and supply of natural gas and current taxes and fees. Retail price of natural gas reviewing is carried out by the regulator in case of price change for natural gas as a commodity, in case of legal requirements changes and other factors that significantly affect end user price of natural gas. Marginal price rate reviewing for natural gas is carried out by the regulator in case of price changing on imported natural gas, in case of changing of the official exchange rate to the U.S. dollar, set by the National Bank of Ukraine, in case of changing the importer’s costs associated with importing purchase and sale of natural gas.</td>
</tr>
</tbody>
</table>
From the table above it can be concluded that a change in commodity prices results in changes of final prices mainly on the request of regulated suppliers and, generally, the whole amount of cost change is carried over to the customers.

Supply service costs, such as costs for billing, contract administration or customer service/call centers, are always included in the allowed revenue for gas supply (see table 21 above). Sometimes also a retail margin is allowed in the regulated revenue of suppliers. In FYR of Macedonia the margin for wholesale trade is 0,5 den/m3 (0.8 eurocent/m3), and the retail supplier earns return of assets.

Having in mind that suppliers collect revenues from delivering a final product to customers, it is reasonable to consider whether the allowed revenue for supply should include an allowance for bad debt or a non-collection rate. The difference between these two terms only develops from the regulatory practice. However, regulators normally do not simply take over the amount of companies’ bad debt allowance into the allowed revenue, but define criteria and formulas for calculating the allowed expense. Before approving a bad debt allowance, the regulatory authorities typically ask companies to prove that they employed all possible measures to collect their receivables and also take into consideration whether the costs for collecting debt are bigger than the losses caused by writing them off.

Among the analyzed gas markets, only in Serbia the maximally allowed percentage of bad debt is included in the regulated revenues of gas suppliers and may be up to 2% of the total allowed revenue.

Finally, the regulatory authorities of the analyzed markets were asked whether regulatory fee is explicitly included in the allowed revenue for gas supply. While all justified costs borne by the regulated suppliers are included in the overall amount of allowed costs and the final tariff (i.e. they are always treated as pass-through costs), the question aimed to identify whether these costs are transparent to the final customers. The tables below summarize the responses received.

---

127 The accounting term used is "bad debt allowance". Bad debts are accounts receivable that will likely remain uncollectable and will be written off. Bad debts appear as an expense on the company's income statement, thus reducing net income. In general, companies make an estimate of bad debt expenses that might be incurred in the current time period based on past records as part of the process of estimating earnings. Most companies make a bad debt allowance since it is unlikely that all of their debtors will pay them in full (www.investorwords.com).
Table 22: Financing of regulatory authority and final gas tariffs and prices

<table>
<thead>
<tr>
<th>Country</th>
<th>Are the costs for financing the regulatory authority included in tariff? If yes, in what tariff(s)?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bosnia and Herzegovina</td>
<td>Yes, implicitly(^{128}), in tariffs for transmission, distribution and supply</td>
</tr>
<tr>
<td>Croatia</td>
<td>Yes, implicitly, in tariffs for gas, supply, distribution, transmission and storage (0.05% of energy undertaking’s total annual revenue in the previous year)</td>
</tr>
<tr>
<td>FYR of Macedonia</td>
<td>Yes, implicitly, in tariffs for all regulated activities (may not exceed 0.1% of revenues of all licensed companies, for 2013-0.037%)</td>
</tr>
<tr>
<td>Georgia</td>
<td>Yes, implicitly, in tariffs for transmission, distribution and supply</td>
</tr>
<tr>
<td>Moldova</td>
<td>Yes, implicitly, in tariffs for transmission, distribution and supply</td>
</tr>
</tbody>
</table>
| Serbia                 | Yes, implicitly, in transmission tariff. Regulatory charge is part of operational costs of the gas transmission operator. This regulatory charge is calculated according to the following formula:  
                          \[ RC_t = 0.9\% \times (AOPEX_t + Dt + WACC_t \times RAB_t) \]  
                          where: \( AOPEX_t \) - adjusted operating cost calculated before inclusion of purchasing value of natural gas for balancing and regulatory charge in period \( t \) |
| Ukraine                | No, the regulatory authority is financed through state budget.                                       |

\(^{128}\) Throughout the table ‘implicitly’ indicates that the costs are not separately displayed to customers.
Summary of Results

Energy sector regulation of energy network industry follows similar principles and criteria for determining network tariffs and, where applicable, end-user prices in all analysed markets. The main finding of this report can be summarized as follows:

1. Network Regulation

1. The most frequently applied price control mechanisms implemented in both the electricity and gas sector are cost-plus (rate of return) regulation or revenue-cap regulation; price-cap regulation is used in only very limited number of cases.

2. For all types of tariff regulation the allowed revenue is determined. This report analyzes the criteria applied for determining the elements of allowed revenue, namely justified operation and maintenance costs, capital costs, compensation for network losses as well as a correction factor addressing variations between the forecast and actual values. Furthermore, this report investigated which principles are followed for regulating electricity and gas end-user prices.

3. In order to facilitate the process of allowed revenue calculation, some regulatory authorities request from regulated companies to prepare and submit separate regulated accounts that to a certain extent differ from national statutory accounting guidelines. Such regulatory accounting rules are used in Albania, Bosnia and Herzegovina, Croatia, Kosovo*, Moldova, Turkey (for electricity) and Ukraine (for gas). Montenegro will apply new regulatory accounting rules as of 1 January 2014.

4. When recognizing operating and maintenance costs in the allowed revenue of a regulated company, regulatory authorities have to ensure maintaining an appropriate level of service, but also to avoid excessive costs being included in the tariff. Deviating from this principle, in Bosnia and Herzegovina (with the exception of its entity Republika Srpska), Croatia and Kosovo* for electricity and in Georgia and Turkey for both electricity and gas the regulator includes all operating and maintenance costs from statutory accounting in the allowed revenue. In all other markets some categories of costs are predefined as justified or non-justified, controllable or non-controllable (and therefore pass-through) and usually subject to regulator's estimation. In FYR of Macedonia the tariff methodologies include even limits for certain cost categories, such as maintenance and labour costs. In case of incentive-based regulation an efficiency factor is applied. However, in the analyzed markets implementing incentive regulation this factor is still very often set to 0% (Albania and Turkey for electricity, Croatia and FYR of Macedonia for gas), mainly due to lack of relevant experience. In some markets the efficiency factors are defined: 4% in Kosovo (electricity), 2% in Moldova (electricity and gas), 0.5 CPI in Montenegro (electricity).

5. Return on assets is typically calculated as a product of the regulatory asset base and rate of return in almost all investigated markets. The exception is Ukraine, where the
calculation of allowed revenue is done by taking into account reasonable level of costs and projected profit, not determined as a return on capital employed (however, for five privatized electricity distribution companies in Ukraine the rate of return is determined, similar as in other analyzed markets).

6. Having in mind the substantial impact of the value of the regulatory asset base on the return on assets and therefore on the final tariffs, regulatory authorities in some countries have the right to re-evaluate assets for the purpose of tariff determination (Albania, Bosnia and Herzegovina for electricity and gas distribution, FYR of Macedonia, Georgia, Kosovo*, Montenegro, Turkey). However this right has not been exercised by all the regulators.

- In almost all analyzed markets the regulatory authorities approve ex-ante investment plans and monitor their implementation. The realization of investment plans influence the value of the regulatory asset base to the extent the allowed revenue includes some investments in advance, which is the case in Montenegro and FYR of Macedonia, as a way for incentivizing investments, and in Bosnia and Herzegovina-Republika Srpska and Serbia where only part of an investment that will be commissioned in the regulatory period is recognized.

- Some other assets are also considered when deciding on the structure of regulatory asset base, such as intangible assets (recognized in the allowed revenues by regulatory authorities of Albania- for electricity distribution, Bosnia and Herzegovina, Georgia, Montenegro, Serbia, Croatia- for gas and Turkey- for gas transmission) and working capital (recognized in the allowed revenues for electricity by regulatory authorities of Albania, Bosnia and Herzegovina, Croatia and Montenegro; for gas only in Bosnia and Herzegovina- Republika Srpska).

- Capital contributions, such as direct payments by asset users or different grants by governments or other institutions, are excluded from the regulatory asset base in all analyzed markets, in order not to allow earning return on assets not financed by the regulated company. However depreciation of such assets is sometimes allowed.

- Finally, the regulatory asset base may be adjusted on yearly basis in case of incentive-based regulation; this is the case in Moldova (for the purpose of including commissioned investments) and in Montenegro (adjustments for the investments realized below 50% of the value approved in advance). In Croatia, adjustment of the regulatory asset base on yearly basis can be only applied in exceptional cases.

7. Weighted average cost of capital, as commonly used method for calculation of the rate of return in regulated energy business, is applied in all analyzed markets. The resulting rate of return levels in the electricity sector range from 0,67% in Bosnia and Herzegovina to 8,95% in Moldova for transmission and from 3,50% in Bosnia and Herzegovina to 14,12% in Moldova for electricity distribution. In the gas sector, these values are again the lowest in Bosnia and Herzegovina (1,8% for transmission, 0% and 6% for two distribution companies) and highest in Moldova (12,23% for both transmission and distribution).

8. When calculating depreciation, the regulatory authorities of the analyzed markets mostly use straight-line depreciation. In some cases they also determine the asset lives to be used for the allowed revenue calculation; in other cases common accounting rules apply.
9. Definition and criteria for recognizing costs of losses in the allowed revenue of all regulated activities do not differ substantionally between the analysed markets.
- Exceptionally, costs for compensating losses are not included in the allowed revenue for electricity transmission in Bosnia and Herzegovina and Ukraine.
- A separate definition of commercial losses exists only in Moldova for electricity. However, in Bosnia and Herzegovina- Republika Srpska a separate percentage of commercial losses is recognized in the allowed revenue for electricity distribution.
- When deciding on the level of losses allowed in the regulated revenue, the regulators of the investigated markets usually analyze the level of realized losses in the previous years and plans for their decrease as well as the characteristics of the networks. In order to calculate the level of relevant costs, the regulators need also to define a price of the electricity and gas used for valuating losses and this is usually purchase price of energy (in FYR of Macedonia market-based price for electricity losses is applied). Currently allowed levels of losses in the electricity sector range from 0.86% in Georgia (only for one TSO, for the other 3.5%) to 3.66% in Montenegro, for transmission and from 8% in Croatia to 27.40% in Kosovo* for distribution. In gas sector the levels of recognized losses are from 0.03% in Serbia to 5% in Georgia for transmission and from 0.7% in FYR of Macedonia to 5.23% in Moldova for distribution.

10. Once the allowed revenue for the regulated companies is calculated by including all justified costs, some regulatory authorities deduct the revenues earned from non-regulated activities (e.g. congestion or reconnection), with a view to avoid double earnings from the same assets. In electricity sector this is the case in majority of countries (but not in Croatia, Georgia and Moldova) and in gas sector in Croatia, Georgia and Serbia.

11. In order to calculate tariffs, the regulators need to establish the volumes of energy to be used in the relevant process. In the majority of the analyzed markets the regulators prefer having a concrete and provable source of data for quantities used for tariff calculation, such as the energy balance or concluded contracts. However, in most of the markets the regulators also have the right to change the reported volumes, especially in order to take into account the real market transactions.

12. After expiry of the regulatory period the regulatory authorities calculate the difference between the allowed and actually earned revenue and the amount of resulting over- or under-recovery is then compensated in the next regulatory period. The regulatory authorities of the analyzed markets mostly calculate the correction factor based on both realized volumes of transported energy and realized costs.

2. ENERGY PRICE REGULATION

Besides regulating natural monopolies i.e. transmission and distribution of energy, in all analyzed markets regulated end-user prices for both households and non-household customers still exist. The exception is Croatia where the regulated prices are applied only to
households. The allowed revenue for regulated supply of energy includes transmission and distribution costs (charged by suppliers, but transferred afterwards to relevant system operators according to applicable tariff systems), costs of purchased energy, supply service costs and sometimes also a retail margin/profit or a non-collection rate.

- In the electricity sector an allowance for bad debt is included in the allowed revenue in Albania, Bosnia and Herzegovina, FYR of Macedonia, Turkey and Kosovo*, while a profit is recognized in the regulated supply revenue in FYR of Macedonia and Serbia. In Ukraine a profit is included in the regulated distribution and supply revenue.

- In the gas sector, a non-collection rate is included in the allowed revenue for supply in Serbia. In case the commodity price changes, this results in changes in final prices also, usually not automatically, but on the request of regulated suppliers (in some cases every year). Generally, the whole amount of cost change is carried over to the customers.

3. UNIVERSAL SERVICE – DEFAULT SUPPLIER – PUBLIC SERVICE OBLIGATION

Specifically for electricity, the concept of universal service is used for the regulated supply in all analyzed markets, with the exception of Ukraine. Universal service is provided by a supplier of last resort in all analyzed markets. Furthermore in some countries the definition of default supplier also exists in addition (Bosnia and Herzegovina and Croatia for households).

Finally, the provision of universal service or fulfillment of public service obligation in the sense of implementing regulation of end-user prices is in many cases are limited in time. In Albania, Croatia, Serbia, Turkey and Ukraine the implementation of regulated prices for households and small enterprises has no time limitation. In all other examined markets the final deadline for abandoning regulated end-user prices for households is 1st January 2015 and for small enterprises in some cases even earlier.

4. OTHER FEES

Finally, some other charges or fees are also included in the regulated tariffs or end-user prices, such as fees for financing regulatory authorities or support for renewable energy sources.

- With the exception of Ukraine, the regulatory fee is included implicitly (not visible on the bill) in all tariffs in all analyzed markets (in Serbia only in transmission tariff).

- Support for electricity from renewable energy sources is included in wholesale public supply tariff in Albania, in wholesale price (feed in tariffs) and in transmission/distribution tariffs (renewable generation connection costs) in Ukraine, in supply tariffs in Bosnia and Herzegovina, Croatia, Kosovo*, Moldova and Turkey (in Croatia and Bosnia and
Herzegovina also visible on the electricity bill) and in the tariff for organization and operation of the market in FYR of Macedonia.
Questionnaire

GAS

TRANSMISSION

1. Type of implemented regulation:
   - [ ] Cost plus
   - [ ] Revenue cap
   - [ ] Price cap
   - [ ] Other (if implemented, please explain below)

2. Length of regulatory period:

3. Are there regulatory accounting guidelines/rules applicable for tariff regulation?
   - [ ] Yes
   - [ ] No

   If yes, please provide reference below:

4. Are all operation and maintenance costs from the statutory accounting recognized in the allowed revenue?
   - [ ] Yes
   - [ ] No

   If no, please provide below criteria for recognition of OPEX in the allowed revenue i.e. what costs are defined as justified/non-justified, are there some costs predefined as controllable and non-controllable, are there predetermined limits for certain costs:
5. In case of incentive based regulation, what is the percentage of the currently applied efficiency factor? Please also clarify whether this is yearly based information or it refers to total efficiency factor for the whole regulatory period? Is efficiency factor sector based or individual (company based)? If individual, please provide percentages for all companies.

6. When determining the cost efficiency (X factor), do you implement benchmarking procedures?

- [ ] Yes, for controllable part of OPEX
- [ ] Yes, for total OPEX
- [ ] Yes, for OPEX and CAPEX (TOTEX)
- [ ] No

If yes, please provide explanation of the implemented benchmarking methodology (whether it is uni-dimensional or multi-dimensional; parametric (COLS, SFA) or non-parametric (DEA, SDEA), other?)

7. Has the regulator the right to re-evaluate assets if deems necessary?

- [ ] Yes
- [ ] No

If yes, under what circumstances and what methodology may be used?

8. Have assets been re-evaluated in the process of tariff regulation?

- [ ] Yes
9. What are the criteria for including or not including certain assets in the RAB? What is the legal background for this?

10. Does the regulator approve investment plans ex-ante?

☐ Yes
☐ No

11. Does the regulator monitor the implementation of investment plan? How does it influence RAB ex-post?

☐ Yes
☐ No

12. Are assets under construction included in the RAB?

☐ Yes
☐ No

If yes, please explain how are they included e.g. only ex-post (when assets in use) or ex-ante (as a way of incentivizing investments; if applied, please explain how it is evaluated):

13. Depreciation method implemented

☐ Straight-line depreciation
☐ Accelerated depreciation
☐ Other
If other, please explain:

If depreciation method differs for old and new (for the regulatory period), assets please explain:

14. Please provide the list of asset lives of the most important assets (pipes, compressor stations, etc.)

15. Does the regulator define asset lives for the regulatory purposes?

☐ Yes
☐ No

16. Are the assets funded by capital contributions (e.g. connection charges) included in RAB?

☐ Yes
☐ No

Please provide brief explanation of the approach:

17. Is depreciation of assets funded by capital contributions recognized in the allowed revenue?

☐ Yes
☐ No

Please provide brief explanation of the approach:
18. Are intangible assets included in RAB?

☐ Yes
☐ No

Please provide brief explanation of the approach:

19. Is working capital included in RAB?

☐ Yes
☐ No

If yes, please explain how it is calculated:

20. In case of regulatory period longer than 1 year, how do you treat RAB during the regulatory period (e.g. are there any automatic adjustments or yearly based revision?)

21. Rate of return calculated as:

☐ WACC
☐ Other

If other, please explain the approach:
22. Please complete the tables below, if applicable:

<table>
<thead>
<tr>
<th>WACC (real, pre-tax)</th>
<th>Gearing (debt/(debt+equity))</th>
<th>Return on equity</th>
<th>Return on debt</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Risk free rate</th>
<th>Beta coefficient</th>
<th>Market return</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
</tbody>
</table>

Please explain how do you determine risk free rate, beta coefficient and market return:

Please explain below how is return on equity and/or return on debt calculated, if not by using CAPM for Re and company’s weighted debt for Rd:

23. Please provide the definition of losses recognized in the allowed revenue, both technical and commercial, if applicable:

24. Please describe the procedure and criteria for recognizing losses in the allowed revenue for transmission, for both technical and commercial losses (including the list of information the regulator requires from the transmission company):

25. Please provide the currently allowed percentage(s) of losses in the transmission network:

26. How is the price for allowed losses determined?

27. What kind of stranded costs, if any, are recognized in the allowed revenue and to what extent are they recognized? Please provide relevant criteria
28. Are there any revenues transmission system operator earns (i.e. revenues from non-regulated activities, but performed by using regulated asset base) that are deducted from the allowed revenue? If yes, please explain which revenues.

29. When calculating transmission tariffs, how do you determine quantities taken into consideration? Please provide legal reference to this.

30. After expiry of a regulatory period, how do you calculate correction of the allowed revenue (the amount of over/under-recovery that is to be compensated in the next regulatory period)?

- [ ] Only by taking into consideration actual quantities transported
- [ ] Taking into consideration actual quantities, but also by comparing planned and realized costs
- [ ] Other

Please provide legal reference:

Please explain briefly the applied criteria and the method of calculation:
DISTRIBUTION

1. Type of implemented regulation:
   - Cost plus
   - Revenue cap
   - Price cap
   - Other (if implemented, please explain below)

2. Length of regulatory period:

3. Are there regulatory accounting guidelines/rules applicable for tariff regulation?
   - Yes
   - No
   
   If yes, please provide reference below:

4. Are all operation and maintenance costs from the statutory accounting recognized in the allowed revenue?
   - Yes
   - No
   
   If no, please provide below criteria for recognition of OPEX in the allowed revenue i.e. what costs are defined as justified/non-justified, are there some costs predefined as controllable and non-controllable, are there pre-determined limits for certain costs:

5. In case of incentive based regulation, what is the percentage of the currently applied efficiency factor? Please also clarify whether this is yearly based information or it refers to total efficiency factor for the whole regulatory period? Is efficiency factor sector based or individual (company based)? If individual, please provide percentages for all companies.
6. When determining the cost efficiency (X factor), do you implement benchmarking procedures?

☐ Yes, for controllable part of OPEX
☐ Yes, for total OPEX
☐ Yes, for OPEX and CAPEX (TOTEX)
☐ No

If yes, please provide explanation of the implemented benchmarking methodology (whether it is uni-dimensional or multi-dimensional; parametric (COLS, SFA) or non-parametric (DEA, SDEA), other?)

7. Has the regulator the right to re-evaluate assets if deems necessary?

☐ Yes
☐ No

If yes, under what circumstances and what methodology may be used?

8. Have assets been re-evaluated in the process of tariff regulation?

☐ Yes
☐ No

If yes, what methodology has been used (historic costs, replacement costs, other)?
9. What are the criteria for including or not including certain assets in the RAB? What is the legal background for this?

10. Does the regulator approve investment plans ex-ante?

☐ Yes
☐ No

11. Does the regulator monitor the implementation of investment plan? How does it influence RAB ex-post?

☐ Yes
☐ No

12. Are assets under construction included in the RAB?

☐ Yes
☐ No

If yes, please explain how are they included e.g. only ex-post (when assets in use) or ex-ante (as a way of incentivizing investments; if applied, please explain how it is evaluated):

13. Depreciation method implemented:

☐ Straight-line depreciation
☐ Accelerated depreciation
☐ Other

If other, please explain:

If depreciation method differs for old and new (for the regulatory period) assets, please
14. Please provide the list of asset lives of the most important assets (pipes, compressor stations, etc.):

15. Does the regulator define asset lives for the regulatory purposes?
   - Yes
   - No

16. Are the assets funded by capital contributions (e.g. connection charges) included in RAB?
   - Yes
   - No

   Please provide brief explanation of the approach:

17. Is depreciation of assets funded by capital contributions recognized in the allowed revenue?
   - Yes
   - No

   Please provide brief explanation of the approach:

18. Are intangible assets included in RAB?
   - Yes
   - No

   Please provide brief explanation of the approach:
19. Is working capital included in RAB?

☐ Yes
☐ No

If yes, please explain how it is calculated:

20. In case of regulatory period longer than 1 year, how do you treat RAB during the regulatory period (e.g. are there any automatic adjustments or yearly based revision?)

21. Rate of return calculated as:

☐ WACC
☐ Other

If other, please explain the approach:

22. Please complete the tables below, if applicable:

| WACC (real, pre-tax) | Gearing (debt/(debt+equity)) | Return on equity | Return on debt |
Please explain how you determine risk free rate, beta coefficient and market return:

Please explain below how is return on equity and/or return on debt calculated, if not
by using CAPM for Re and company's weighted debt for Rd:

23. Please provide the definition of losses, both technical and commercial, recognized in the allowed revenue:

24. Please describe the procedure and criteria for recognizing losses in the allowed revenue for distribution, for both technical and commercial (including the list of information the regulator requires from the distribution company):

25. Please provide the currently allowed percentage(s) of losses in the distribution network (if allowed differently for different companies, please provide all):

26. How is the price for allowed losses determined?

27. What kind of stranded costs, if any, are recognized in the allowed revenue and to what extent are they recognized? Please provide relevant criteria

28. Are there any revenues distribution system operator earns (i.e. revenues from non-regulated activities, but performed by using regulated asset base) that are deducted from the allowed revenue? If yes, please explain which revenues.
29. When calculating distribution tariffs, how do you determine quantities taken into consideration? Please provide legal reference to this.

30. After expiry of a regulatory period, how do you calculate correction of the allowed revenue (the amount of over/under-recovery that is to be compensated in the next regulatory period)?

- Only by taking into consideration actual quantities distributed
- Taking into consideration actual quantities, but also by comparing planned and realized costs
- Other

Please provide legal reference:

Please explain briefly the applied criteria and the method of calculation:
SUPPLY (if regulated)

1. Please provide definition (list) of supply service costs recognized in the final regulated price of gas:

2. Are bad debts recognized in the final regulated price of gas?
   - [ ] Yes
   - [ ] No

   If yes, please provide the criteria for their recognition:

3. Is non-collection recognized in the final regulated price of gas?
   - [ ] Yes
   - [ ] No

   If yes, what is the percentage currently allowed:

   If yes, how is this allowance determined (what are the criteria implemented)?

4. How is the change in commodity prices treated in the final price regulation? Is there some kind of automatic mechanism applied? Please provide also legal reference to this:
OTHER:

1. Are the costs for financing the regulatory institution included in tariff?

☐ Yes
☐ No

If yes, please explain in what tariff(s):

If yes, please explain how it is determined (please provide legal reference)
1. Type of implemented regulation:

- Cost plus
- Revenue cap
- Price cap
- Other (if implemented, please explain below)

2. Length of regulatory period:

3. Are there regulatory accounting guidelines/rules applicable for tariff regulation?

- Yes
- No

If yes, please provide reference below:

4. Are all operation and maintenance costs from the statutory accounting recognized in the allowed revenue?

- Yes
- No

If no, please provide below criteria for recognition of OPEX in the allowed revenue i.e. what costs are defined as justified/non-justified, are there some costs predefined as controllable and non-controllable, are there pre-determined limits for certain costs:

5. In case of incentive based regulation, what is the percentage of the currently applied efficiency factor? Please also clarify whether this is yearly based information or it refers to total efficiency factor for the whole regulatory period? Is efficiency factor sector based or individual (company based)? If individual, please provide percentages for all companies.
6. When determining the cost efficiency (X factor), do you implement benchmarking procedures?

☐ Yes, for controllable part of OPEX

☐ Yes, for total OPEX

☐ Yes, for OPEX and CAPEX (TOTEX)

☐ No

If yes, please provide explanation of the implemented benchmarking methodology (whether it is uni-dimensional or multi-dimensional; parametric (COLS, SFA) or non-parametric (DEA, SDEA), other?)

7. How are the costs related to reactive power treated when calculating allowed revenue?

8. Has the regulator right to re-evaluate assets if deems necessary?

☐ Yes

☐ No

If yes, under what circumstances and what methodology may be used?

9. Have assets been re-evaluated in the process of tariff regulation?

☐ Yes

☐ No

If yes, what methodology has been used (historic costs, replacement costs, other)?
10. What are the criteria for including or not including certain assets in the RAB? What is the legal background for this?

11. Does the regulator approve investment plans ex-ante?
   - Yes
   - No

12. Does the regulator monitor the implementation of investment plan? How does it influence RAB ex-post?
   - Yes
   - No

13. Are assets under construction included in the RAB?
   - Yes
   - No

   If yes, please explain how are they included e.g. only ex-post (when assets in use) or ex-ante (as a way of incentivizing investments; if applied, please explain how it is evaluated):

14. Depreciation method implemented
   - Straight-line depreciation
   - Accelerated depreciation
   - Other

   If other, please explain:
If depreciation method differs for old and new (for the regulatory period) assets, please explain:

15. Please provide the list of asset lives of the most important assets (network, substations, etc.)

16. Does the regulator define asset lives for the regulatory purposes?
   - Yes
   - No

17. Are the assets funded by capital contributions (e.g. connection fees) included in RAB?
   - Yes
   - No

   Please provide brief explanation of the approach:

18. Is depreciation of assets funded by capital contributions recognized in the allowed revenue?
   - Yes
   - No

   Please provide brief explanation of the approach:

19. Are intangible assets included in RAB?
20. Is working capital included in RAB?

☐ Yes
☐ No

If yes, please explain how it is calculated:

21. In case of regulatory period longer than 1 year, how do you treat RAB during the regulatory period (e.g. are there any automatic adjustments or yearly based revision?)

22. Rate of return calculated as:

☐ WACC
☐ Other

If other, please explain the approach:
23. Please complete the tables below, if applicable:

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Please explain how do you determine risk free rate, beta coefficient and market return:

Please explain below how is return on equity and/or return on debt calculated, if not by using CAPM for Re and company's weighted debt for Rd:

24. Please provide the definition of losses recognized in the allowed revenue, both technical and commercial, if applicable:

25. Please describe the procedure and criteria for recognizing losses in the allowed revenue for transmission, for both technical and commercial (including the list of information the regulator requires from the transmission company):

26. Please provide the currently allowed percentage(s) of losses in the transmission network:

27. How is the price for allowed losses determined?

28. What kind of stranded costs, if any, are recognized in the allowed revenue and to what extent are they recognized? Please provide relevant criteria.
29. Are there any revenues transmission system operator earns (i.e. revenues from non-regulated activities, but performed by using regulated asset base, e.g. revenues from congestion) that are deducted from the allowed revenue? If yes, please explain which revenues.

30. When calculating transmission tariffs, how do you determine quantities taken into consideration? Please provide legal reference to this.

31. After expiry of a regulatory period, how do you calculate correction of the allowed revenue (the amount of over/under-recovery that is to be compensated in the next regulatory period)?

- Only by taking into consideration actual quantities transported
- Taking into consideration actual quantities, but also by comparing planned and realized costs
- Other

Please provide legal reference:

Please explain briefly the applied criteria and the method of calculation:

32. What kind of ancillary services costs, if any, are recognized in the allowed revenue and how? Please provide relevant criteria (type of ancillary services and unit prices)
1. Type of implemented regulation:

☐ Cost plus
☐ Revenue cap
☐ Price cap
☐ Other (if implemented, please explain below)

2. Length of regulatory period:

3. Are there regulatory accounting guidelines/rules applicable for tariff regulation?

☐ Yes
☐ No

If yes, please provide reference below:

4. Are all operation and maintenance costs from the statutory accounting recognized in the allowed revenue?

☐ Yes
☐ No

If no, please provide below criteria for recognition of OPEX in the allowed revenue i.e. what costs are defined as justified/non-justified, are there some costs predefined as controllable and non-controllable, are there predetermined limits for certain costs:

5. Do allowed costs include cost of reserves?

☐ Yes
☐ No
6. In case of incentive based regulation, what is the percentage of the currently applied efficiency factor? Please also clarify whether this is yearly based information or it refers to total efficiency factor for the whole regulatory period? Is efficiency factor sector based or individual (company based)? If individual, please provide the percentage for several representative companies.

7. When determining the cost efficiency (X factor), do you implement benchmarking procedures?
   - [ ] Yes, for controllable part of OPEX
   - [ ] Yes, for total OPEX
   - [ ] Yes, for OPEX and CAPEX (TOTEX)
   - [ ] No

   If yes, please provide explanation of the implemented benchmarking methodology (whether it is uni-dimensional or multi-dimensional; parametric (COLS, SFA) or non-parametric (DEA, SDEA), other?)

8. How are the costs related to reactive power treated when calculating allowed revenue?

9. Has the regulator right to re-evaluate assets if deems necessary?
   - [ ] Yes
   - [ ] No

   If yes, under what circumstances and what methodology may be used?

10. Have assets been re-evaluated in the process of tariff regulation?
    - [ ] Yes
11. What are the criteria for including or not including certain assets in the RAB? What is the legal background for this?

12. Does the regulator approve investment plans ex-ante?
   - [ ] Yes
   - [ ] No

13. Does the regulator monitor the implementation of investment plan? How does it influence RAB ex-post?
   - [ ] Yes
   - [ ] No

14. Are assets under construction included in the RAB?
   - [ ] Yes
   - [ ] No

   If yes, please explain how are they included e.g. only ex-post (when assets in use) or ex-ante (as a way of incentivizing investments; if applied, please explain how it is evaluated):

15. Depreciation method implemented:
   - [ ] Straight-line depreciation
☐ Accelerated depreciation
☐ Other

If other, please explain:

If depreciation method differs for old and new (for the regulatory period) assets, please explain:

16. Please provide the list of asset lives of the most important assets (network, substations, etc.):

17. Does the regulator define asset lives for the regulatory purposes?
   ☐ Yes
   ☐ No

18. Are the assets funded by capital contributions (e.g. connection charges) included in RAB?
   ☐ Yes
   ☐ No

Please provide brief explanation of the approach:

19. Is depreciation of assets funded by capital contributions recognized in the allowed revenue?
   ☐ Yes
   ☐ No

Please provide brief explanation of the approach:
20. Are intangible assets included in RAB?

☐ Yes
☐ No

Please provide brief explanation of the approach:

21. Is working capital included in RAB?

☐ Yes
☐ No

If yes, please explain how it is calculated:

22. In case of regulatory period longer than 1 year, how do you treat RAB during the regulatory period (e.g. are there any automatic adjustments or yearly based revision?)

23. Rate of return calculated as:

☐ WACC
☐ Other

If other, please explain the approach:
24. Please complete the tables below, if applicable:

<table>
<thead>
<tr>
<th>WACC (real, pre-tax)</th>
<th>Gearing (debt/(debt+equity))</th>
<th>Return on equity</th>
<th>Return on debt</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Risk free rate</th>
<th>Beta coefficient</th>
<th>Market return</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>%</td>
<td>%</td>
</tr>
</tbody>
</table>

Please explain how do you determine risk free rate, beta coefficient and market return:

Please explain below how is return on equity and/or return on debt calculated, if not by using CAPM for Re and company’s weighted debt for Rd:

25. Please provide the definition of losses, both technical and commercial, recognized in the allowed revenue:

26. Please describe the procedure and criteria for recognizing losses in the allowed revenue for distribution, for both technical and commercial (including the list of information the regulator requires from the distribution company):

27. Please provide the currently allowed percentage(s) of losses in the distribution network (if allowed differently for different companies, please provide all):
28. How is the price for allowed losses determined?

29. What kind of stranded costs, if any, are recognized in the allowed revenue and to what extent are they recognized? Please provide relevant criteria.

30. Are there any revenues distribution system operator earns (i.e. revenues from non-regulated activities, but performed by using regulated asset base) that are deducted from the allowed revenue? If yes, please explain which revenues.

31. When calculating distribution tariffs, how do you determine quantities taken into consideration? Please provide legal reference to this.

32. After expiry of a regulatory period, how do you calculate correction of the allowed revenue (the amount of over/under –recovery that is to be compensated in the next regulatory period)?

- [ ] Only by taking into consideration actual quantities distributed
- [ ] Taking into consideration actual quantities, but also by comparing planned and realized costs
- [ ] Other

Please provide legal reference:

Please explain briefly the applied criteria and the method of calculation:
1. Please provide definition (list) of supply service costs recognized in the final regulated price of electricity:

2. Are bad debts recognized in the final regulated price of electricity?
   - ☐ Yes
   - ☐ No

   If yes, please provide the criteria for their recognition:

3. Is non-collection recognized in the final regulated price of electricity?
   - ☐ Yes
   - ☐ No

   If yes, what is the percentage currently allowed:

   If yes, how is this allowance determined (what are the criteria implemented)?

4. How is the change in commodity prices treated in the final price regulation? Is there some kind of automatic mechanism applied? Please provide also legal reference to this:
1. Does your legislation recognize default supplier and the supplier of last resort:

   Default supplier:
   - Yes
   - No

   Supplier of last resort:
   - Yes
   - No

2. Which end-use customers have the right to resort to the default supplier/supplier of last resort (tariff):

   - Households
   - Small enterprises
   - All customers

   Share of households under default tariff (of total households):
   %

3. Indicate if your legislation specified a methodology for universal service:

   For default supplier:
   - Yes
   - No

   For the supplier of last resort:
   - Yes
   - No

4. Which institution in your country is the price setting authority (for regulated retail prices):

   - NRA
   - Ministry (of Economy etc.)
   - Other

5. How is commodity (energy) that is sold by the retailers to the consumers at regulated tariff as universal service procured:

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129 As described in Article 3(3) of Directive 2003/54/EC
6. What is the time limit for the supply under the last resort service:

For default supplier:

☐ No time limit
☐ Time limit:

Indicate the time limit:

weeks

7. The case in which default or supplier of last resort is applicable:

☐ Customer non-payment
☐ Customer cannot find a supplier
☐ Supplier going bankrupt
☐ Customer does not choose a supplier
☐ Expired contract
☐ Other:

Please indicate the reason:

8. Do you have proposed time schedule for abandoning of the regulated price for households and small enterprises:

☐ No
☐ Yes

Indicate the year (for example in 2017):

for households
for small enterprises
OTHER:

1. Are the costs for financing the regulatory institution included in tariff?
   
   [ ] Yes
   [ ] No

   If yes, please explain in what tariff(s):

   If yes, please explain how it is determined (please provide legal reference)

2. Is RES support allowance included in tariff?
   
   [ ] Yes
   [ ] No

   If yes, please explain in what tariff(s):

   If yes, please explain how it is determined (please provide legal reference)