

ELECTRICITY REGULATORY ENTITY

ELECTRICITY DISTRIBUTION SYSTEM OPERATOR TARIFF CALCULATION METHODOLOGY

PART I

This methodology is assuming that Distribution System Operator (DSO) and Retail Public Supplier (RPS) are within the same company

Authority

This electricity distribution system operator tariff calculation methodology is developed according to the Law No.9072, dated May 22, 2003, “On Power Sector”, as amended.

Purpose

The purpose of this methodology is to set distribution use-of-network tariff based on sound tariff principles and detailing the necessary data needed for fair and transparent tariff setting.

Objective

The **objective** of this tariff methodology is to establish the methodology for the calculation of the distribution access and use-of-network for the distribution system users of Albania that is consistent with the Energy Community for South East Europe (ECSEE) Treaty, and enable non-tariff customers and merchant power plants to participate in the regional electricity market.

1. Terms used in the methodology

Standard terms used in all tariff methodologies are established in the Power Sector Law, Market Rules, Metering Code, Transmission Code and other secondary legislation approved by the ERE. Terms used in this methodology have the following meanings.

- 1.1 **Annual adjustment factor (A)** – a percentage equal to the inflation factor minus the efficiency improvement factor applied to price cap for the previous rate year.
- 1.2 **Base distribution tariff** – the set of distribution service tariff values determined according to costs in the base year.
- 1.3 **Base year** – the first year of a regulatory period
- 1.4 **Tariff customers** – RPS customers

- 1.5 **Test year** - a 12-month period prior to a regulatory period that is used as the basis for developing the revenue requirements for the base year for the DSO.
- 1.6 **Efficiency improvement factor (X factor)** – the annual percentage reduction in the cost of distribution service resulting from improvements in operational efficiency and improvements in technology
- 1.7 **Cap Regulation** – the use of regulatory periods in which either the revenues of the licensee or the maximum price of the licensees are adjusted during those regulatory periods.
- 1.8 **Regulated asset base (RAB)** – the value of fixed assets as defined in Article 6.1 of this tariff methodology.
- 1.9 **Regulatory period** – a multi-year period when prices or revenues requirements are allowed to change at specific rates.

2. General regulations and basic principles

- 2.1 Non-compliance with any part of this Regulation may result in a rejection by the ERE of DSO tariff application.
- 2.2 This methodology is developed in conformity with Law on Power Sector as well as other legal acts which are in force in the Republic of Albania and other secondary legislation approved by the ERE.
- 2.3 The ERE will establish the tariff for the distribution system operator based on the principles that:
 - There should be no cross-subsidies between customer classes;
 - Tariffs for the DSO should reflect the actual cost of service for each customer class according to each voltage level;
 - Tariffs should provide proper price signals for the efficient use of the distribution network;
 - Expenses included in the tariff should be transparent to all stakeholders;
 - The tariff should allow the distribution system operator a reasonable opportunity to earn the ERE-approved allowed rate of return on the ERE-approved regulated asset base;
 - Only prudently acquired services and assets will be accepted into the tariff for the distribution system operator; and,
 - Prices for distribution services should remain relatively stable over time.
- 2.4 Revenue associated with the use of the distribution system should be collected from RPS tariff and non-tariff customers in a transparent and non-discriminatory fashion. Comparable groups of tariff, non-tariff customers and generating plants connected to

the distribution system should pay the same distribution use of network charges, directly or indirectly.

- 2.5 Tariff customers will be allocated the costs of energy losses associated with their voltage level. Energy use by customers that are not metered at their commercial point of service delivery will be adjusted to cover for energy losses from the commercial point to the metered point.
- 2.6 Power cost required to meet the annual target for distribution losses (pursue the targets approved in this methodology) is included in the distribution service tariff by voltage level.

3. Regulatory Periods, Test Year and Base Year

- 3.1 The ERE will decide on the appropriate regulatory periods for the distribution system operator using the price cap tariff methodology.
- 3.2 The ERE will adopt template tables for tariff applications. The distribution system operator shall use the template tables provided by ERE when filing a rate application for a regulatory period. The format of the tables can be modified as long as the information is organized in a similar manner and the breakdown of information is no less than that provided in the approved template tables. The tables will show test year results, adjustments made to test year and resulting base year including but not limited to company expenses, capital expenditures, and regulated asset base by regulated service.
- 3.3 The regulatory periods will be consistent for transmission network services, distribution network services.
- 3.4 The tariff should allow for recovery of the cost of ownership, construction, operation, and maintenance of lines, cables, transformer substations, transformers, and related buildings and communication facilities (and any other facilities related to the provision of distribution access services).
- 3.5 Price cap regulation is applied to the average tariff. ERE approves the average change in price for each regulatory period.
- 3.6 An “RPI-X” approach is used to give the distribution system operator an incentive to improve the efficiency of its operations during the regulatory period.
- 3.7 Long-term debt financing should be used to finance for repair and renovation of existing and new capital expenditures, but should not be used to cover operating costs.
- 3.8 The distribution system operator shall clearly and unambiguously report the costs of each regulated service including only the assets and activities related to the regulated services. The cost allocation method shall be comprehensive and approved by the ERE.
- 3.9 Costs included in the tariff for the distribution system operator shall correspond to costs that would be incurred by a well-managed distribution system operator which

makes prudent investments, minimizes network losses, and avoids wasteful expenditures. When setting the distribution system operator tariffs for the base year, the ERE has the right to investigate the cost levels reported by the distribution system operator, and benchmark its unit costs against other distribution system operator in the region taking into consideration the differences in characteristics of those distribution system operators.

- 3.10 In preparing a tariff application, the distribution system operator shall try to present all costs with precision up to 100,000 Leke. The regulator should not question amounts less than 100,000 Leke unless there is a dispute about compensation or payment to specific physical persons.

4. Electric energy and power balances

- 4.1 The electric energy balance of the distribution system for the base year shall be prepared by estimating the total amount of energy in GWh received by the distribution system operator during the base year. This total equals energy received from the transmission system plus energy received from generating stations connected to the distribution system. Total energy received must be allocated to:
- a) energy delivered to RPS tariff customers
 - b) energy delivered to non-tariff customers
 - c) technical energy losses in the distribution system
 - d) non-technical energy losses in the distribution system.
- 4.2 The coincident peak load flow balance of the distribution system shall be prepared by estimating the total power in MW received by the distribution system in the peak hour. This total equals power received from the transmission system plus power received from generating stations connected to the distribution system. Total power received must be allocated to:
- a) power delivered to RPS tariff customers
 - b) power delivered to non-tariff customers
 - c) technical power losses in the distribution system
 - d) non-technical power losses in the distribution system.
- 4.3 The distribution system operator will calculate the total sum of all non-coincidental loads by voltage level for all customers with connection capacity greater than 50 kVA.
- 4.4 Energy and power balances for the combined transmission and distribution system are not an acceptable substitute for balances for the distribution system.
- 4.5 For each of the last ten years, energy losses in the distribution system must be shown as a percentage of energy received by the distribution system.

5. Revenue Requirements for the Base Year

- 5.1 The test year expenses for establishing base financial costs will be based on accounting information in accordance with the ERE-approved Uniform System of Accounts. The test year should be a representative 12-month historical period of company operating costs. The ERE has the right to perform, or contract to perform, a regulatory audit of the distribution system operator's test year accounting information during the rate application proceedings.
- 5.2 The distribution system operator may propose changes to the test year expense results for setting tariff for the base year of the next regulatory period. Any such changes must be both known (a specific item) and measurable (quantifiable). Contingency funds to cover unexpected costs will not be approved by the ERE. The ERE will consider adjustments to test year results such as:
- 1) demand growth or decreases;
 - 2) inflation;
 - 3) contract price changes;
 - 4) changes in taxes and insurance;
 - 5) the number of customers served;
 - 6) increased levels of the regulatory asset base;
 - 7) cost of capital;
 - 8) level of depreciation expense; and,
 - 9) efficiency factor.
- 5.3 The distribution system operator will provide justification for each forecasted adjustment to the test year results. The adjustments must be specified on the tables provided by the distribution system operator in the rate application and written testimony will be included in the rate application providing evidence for the reason(s) for each adjustment and the amount for each adjustments.
- 5.4 For licensed services regulated under price cap regulation, the distribution system operator will provide estimated factors to be included for each rate year in the regulatory period. The factors will include:
- 1) Average annual cumulative regulatory asset base for the regulatory period;
 - 2) Total energy losses;
 - 3) Annual Inflation factor; and,
 - 4) Annual Efficiency Factor.
- 5.5 Revenue requirements for the base year will be calculated as follows:

$$RR = C + (RAB * WACC)$$

where:

RR are the annual revenue requirements;

C the allowed annual costs of operation for the licensed activity,

RAB the Regulatory Asset Base;

WACC = The Before-Tax Weighted Average Cost of Capital

$$\mathbf{WACC = [ES * ARoE / (1-T)] + (DS * CoD)}$$

$$\mathbf{ES + DS = 1}$$

Where:

ES = Target for equity ratio of the RAB

T = Corporate Tax Rate

ARoE = Allowed return on equity after tax

DS = Target for debt ratio of the RAB

CoD = Cost of debt

- 5.6 Payments associated with leasing (for example, motor vehicle leasing) may be included in operating expenditures.
- 5.7 The distribution system operator's operating costs that can be included in the revenue requirements for licensed services are specified within the template tables for distribution system operator application.
- 5.8 The distribution system operator will develop for ERE approval the average level of technical losses on the distribution network at each voltage level. The cost of purchasing energy/capacity to satisfy non technical energy losses would be an operating expense allocated to RPS (tariff customers) at various voltage levels. The cost of purchasing energy/capacity to satisfy technical energy losses will be an operating expense of the distribution system operator allocated to Use of Network services at the various voltage levels.
- 5.9 Revenue requirements include all fees paid to ERE by the distribution system operator except for fines and sanction-related costs.

6. Return on Regulatory Asset Base

- 6.1 The regulatory asset base for a licensed service includes both tangible and intangible assets less accumulated depreciation plus a working capital component. The RAB is calculated according to the following formula:

$$RAB = A - CG - D + WC + INV ;$$

where:

RAB the Regulatory Asset Base;

- A the recognized value of used and useful fixed assets at the beginning of the regulatory period;
- CG the value of assets acquired through gratuitous transfer or constructed with financial resources of electricity consumers;
- D the accumulated depreciation for the past period of asset used to perform the licensed activity; Depreciation for new investments during the regulatory period will equal the mid year average annual cumulative depreciation
- WC the working capital requirement;
- INV the forecast of the mid-year average cumulative nominal amount of investments approved by the ERE, which will be invested during the regulatory period.
- 6.2 The ERE will approve the RAB for the base year. Not all assets of the distribution system operator may be included in the regulatory asset base for a separately priced licensed service. Assets that do not support the licensed service will be disallowed from the regulatory asset base. Examples of disallowed assets include assets used for non-licensed activities, recreational facilities, and assets purchased by the distribution system operator above market value. The ERE based on its consultant or its own staff evaluation should determine the market value only in cases of disputed levels of investment.
- 6.3 Prudent levels of investment approved by the ERE may be included in the regulatory asset base for the distribution system operator's services for the initial regulatory periods. The distribution system operator will provide the ERE with written testimony on the breakdown of the proposed investment program for the regulatory period, providing details how each major category will provide additional needed capacity or improve service and energy quality performance.
- 6.4 The distribution system operator shall show the estimated accumulated depreciation and amortization for all assets in the regulatory asset base through the last year of the current regulatory period and propose an estimate of the depreciation and amortization for the base year of the next regulatory period.
- 6.5 Regulatory or deferred assets are expenses that are non-recurring or periodically recurring expenses that should be recovered over a period of time by the distribution system operator. Non-recurring expenses may include catastrophic storm damage and rate application expenses.
- 6.6 Depreciation of assets will be based on the most recent depreciation study provided by the distribution system operator and approved by the ERE that will show the lives of assets by category based on an engineering study. The ERE will apply tax lives on assets for regulatory purposes, but it may decide to use other depreciation rates in specific cases.
- 6.7 The distribution system operator should provide proposals for the amortization of non-tangible assets and regulatory/deferred assets. The ERE will approve all amortization schedules.

- 6.8 The working capital allowance in the regulatory asset base should be based on a study of the funds required to maintain a suitable level of material and supplies and the cash required to meet current obligations and to maintain minimum back accounts. Any such study will be included in the tariff application by the distribution system operator to the ERE. In absence of the study, the distribution system operator may provide an estimate of the working capital allowance with written evidence justifying such an estimate. In any case, the working capital will not exceed 1/12 of OPEX.
- 6.9 Rate of return for the distribution system operator should not reflect any assets acquired through gratuitous transfer.
- 6.10 The distribution system operator will provide the results of any revaluation of tangible assets which was performed in accordance with the Albanian Accountancy Act and International Accounting Standards and which was completed after the last rate application proceeding for the distribution system operator. The distribution system operator will provide a breakdown of the asset, by categories, included in the regulatory asset base, before and after the revaluation.
- 6.11 The ERE will determine the appropriate after-tax Return on Equity for the distribution system operator which will be the rate for a risk less security in Albania plus a risk premium related to the risk inherent in an electricity distribution system operator. ERE will use the Capital Asset Pricing Model or other methodologies, where the ERE will use a number of factors for consideration, including: (1) comparisons with other companies having corresponding risks; (2) the attraction of capital; (3) current financial and economic conditions; (4) the cost of capital; (5) the risk of the enterprise; (6) the financial policy and capital structure of the utility; (7) the competence of management; and, (8) the company's financial history.
- 6.12 The ERE will determine the normalized cost of debt for calculating the debt component interest rates. The calculation of the normalized cost of debt will be based on interest rates for outstanding debt of the distribution system operator. The interest rates used for determining revenue requirements may or may not be the same as actual interest rates for debt. The distribution system operator must show that the interest rates for debt are in-line with commercial interest rates for debt assumed by other companies with similar credit risks. Any debt included in the calculation of average debt interest rate that has an interest rate higher than the current market level will be adjusted downward to the market level.

7. Services and Customer Groups

- 7.1 The distribution system operator will provide five types of services: use-of-network services, metering and meter reading, meter disconnection and reconnection, reactive power compensation, and connection services.
- 7.1.1 Use of network – the DSO will provide access to the network for the retail public supplier, non-tariff customers, qualified suppliers and SPPs. The DSO will charge these customers a capacity charge and an energy charge. The energy charge for the retail public supplier will include overall energy losses, while the energy charge for qualified suppliers, non-tariff customers, and SPPs will not include non-technical losses.

- 7.1.2 Metering and meter reading. The DSO will operate and maintain all metering facilities and read the meters as required for the retail customers connected to DSO network.
- 7.1.3 Meter disconnection and reconnection service. The DSO, upon request of the retail public supplier or qualified supplier or at its own will, disconnect a customer for non-payment or other violation in accordance with the customer service rules. Reconnection will also be made as specified in the customer service rules.
- 7.1.4 Reactive power compensation – The DSO will charge all customers above 50 kVA for reactive power compensation. The calculation for charges, if any, during a month as provided below in Section 11 below.
- 7.1.5 **Connection** – Each new connection will be priced to the retail customers in accordance with the connections rules and Section 12 below.
- 7.2 The RPS will contract for distribution services on behalf of the tariff customers. Non-tariff consumers, qualified suppliers and SPPs will be individually billed by the distribution system operator.
- 7.3 Use-of-network services customers will be separated into customer groups based solely on connection voltage. Some customer subgroups may be created within voltage level.

8. Allocation of costs to energy and capacity use-of-network charges

- 8.1 Each customer must pay an energy charge, in Leke/kWh, based on the number of kWh delivered from the distribution system to the customer during that month.
- 8.2 Customers with the appropriate type of meter will also pay a capacity charge for distribution, if appropriate, in Leke/kW/month, based on the higher of the customer's non-coincidental peak load during the 12-month period ending with the billing month or its contractually guaranteed capacity. A penalty may apply for any non-coincidental peak demand excess above the contractually guaranteed capacity.
- 8.3 In a distribution system operator tariff application, the distribution system operator must forecast the following figures, for each tariff and non tariff customer groups (customers at 110/x kV transformers, medium and low voltage):
 - a) An estimate of the total delivery capacity in kW required to provide a reliable supply of electricity to customers in that customer group.
 - b) the total energy in kWh that will be shown in tariff customers and non-tariff customers' bills in each month of the base year, and the sum of these monthly totals.
 - c) a forecast of the distribution losses attributed to tariff and non-tariff consumers at each voltage level (the cost of losses will be included in the energy charge (variable cost) for each customer group).

- 8.4 For each tariff and non tariff customer group the fixed cost of the revenue requirements is allocated to that group in the base year. The price of capacity, in leke per kW per month, equals:

$$P_{\text{capacity}} = \text{Allocated Fixed Costs} / L$$

L - Total delivery capacity, kW

- 8.5 For each tariff and non tariff customer group (customers at 110/x kV transformers, medium voltage, and low voltage) the energy-related portion of the revenue requirements is allocated to each customer group.

The price of energy, in leke per kWh, equals:

$$P_{\text{energy}} = \text{Allocated Variable Costs} / E$$

E - total energy in kWh that will be shown in tariff customers and non-tariff customers' bills during the base year.

- 8.6 Allocated variable costs for tariff customers will include the cost of providing energy losses, allocated by voltage level. The allocated variable costs for non-tariff customers will include the cost of providing technical energy losses, allocated by voltage level.
- 8.7 For customers whose meters only measure active energy consumption in kWh, the price per kWh is calculated so that it will cover both capacity-related costs and energy-related costs:

$$P_{\text{energy-only}} = (\text{Allocated Fixed Costs} + \text{Allocated Variable Costs}) / E$$

Where, E = total energy in kWh that will be shown in the tariff customers and non-tariff respective customers' bills during the base year.

- 8.8 The Distribution System Operator may submit an application to ERE for peak/off-peak energy prices in the distribution use of network tariff. In this application there will be two values of energy: (i) one corresponding to peak periods (when network losses are higher and the value of energy is higher), and (ii) one corresponding to off-peak periods (when network losses are lower and the value of energy is lower). In other respects the distribution system operator methodology would be the same. The distribution system operator would have to explain in its tariff application the costs and benefits of introducing a peak/off-peak pricing structure in the distribution use of network tariff. The peak/off-peak approach requires more expensive meters, which can be justified only by peak/off-peak price differences for generated and imported energy and in conjunction with on-peak and off-peak pricing by the RPS may justify the purchase of the required meters.

9. Metering Related Services

- 9.1 The Distribution System Operator will offer metering services to the retail public supplier and to qualified suppliers.
- 9.2 The DSO will charge the suppliers a metering and meter reading charge for each customer that each supplier supplies energy. All costs related to the installation, operation, maintenance, calibration and reading of the wholesale and retail customer meters will be include in the allocated revenue requirements for this service, separated by voltage level. The rate will be determined as the total revenue requirements for a particular voltage level divided by the number of customers connected at that voltage level.
- 9.3 The DSO charges for disconnection and reconnection of meters. The revenue requirements for such service should represent the average annual costs of providing these services. There is one price at the time reconnection that will include the cost related to disconnection, which must be pre-paid before the reconnection is made. The allocated revenue requirements for this service should include labor, labor overhead, vehicle-related expenses, and other allocated expenses.

10. Setting the average distribution tariff ceiling

- 10.1 For the base year, the average distribution tariff ceiling is equal to the average distribution tariff calculated according to costs in the base year.
- 10.2 For the second year of the tariff review cycle (Year 2), each component of the distribution use-of-network tariff for the base year is multiplied by the annual adjustment factor:

$$A = (1 + RPI - X)$$

A - annual adjustment factor

RPI - rate of consumer price inflation forecast for Year 2 by the National Bank of Albania, or set by the ERE on the basis of the statistical trends in consumer price index over the most recent 3 year period for which historical data are available (sources from INSTAT).

X - efficiency improvement factor set by ERE

- 10.3 The ERE will add to this formula a performance improvement factor based on the quality of supply to tariff customers and non-tariff customers or the level of distribution network energy losses. Such performance improvement factors must be defined very clearly and simply, and the distribution system operator must provide an assurance to ERE that the distribution system operator is able to provide the quality of supply data needed to accurately measure its performance improvement.

- 10.4 The value of X should be determined on the basis of a benchmarking study of distribution system operators, in which the performance of at least 3 distribution system operators is examined over a period of at least 3 years.
- 10.5 The X-factor will include at least four categories of expenses: direct and indirect labor, labor productivity, procurement, and technology. The technology will include implementation of management systems and reduction in technical losses.
- 10.6 For each succeeding year of the regulatory period, the distribution prices for the previous year are multiplied by an annual adjustment factor as was done in the second Year.

11. Reactive Power Charges

- 11.1 Reactive power compensation is normally an ancillary service provided by generators to the TSO and therefore reactive power charges are part of the transmission tariff. If the distribution system operator continually fails to meet its voltage standard set at the interconnection between the transmission and distribution network, the TSO can charge the distribution system operator reactive power penalties. The Distribution System Operator can install reactive power capacity or reactors as the need requires rather than pay the penalty to the transmission company.
- 11.2 Likewise, the distribution system operator has the right to require a distribution network customer to maintain a certain power factor at the interconnection with the distribution network.
- 11.3 The consumers with provided electrical capacity of 50 kVA and more pay an allowance over the value of the active electric power depending on the reactive electric power used and released at average monthly capacity factor less than 0.9 during the day and peak daylight zone.
- 11.4 The quantity of used reactive electric power, for which an allowance is paid under Section 11.3, is the positive difference between the quantity of used reactive electric power and the product of the quantity of used active electric power and a coefficient corresponding to the average monthly power factor, according to the formula:

$$E_{r\ alwn} = E_{r\ used} - (E_{a\ used} \times (1 - F))$$

where:

$E_{r\ alwn}$ is the quantity of reactive electric power which is paid, kVarh;

$E_{r\ used}$ the quantity of reactive power consumed by the customer during the daytime zones;

$F = 0.9$, for reactive power consumption not charged between 1 and 0.9 power factor.

$E_{a\ used}$ the quantity of active electric power used by the consumer by daytime zones, determined through the readings of the device for commercial metering of active electric power, kWh.

- 11.5 The consumers under Section 11.3 pay an allowance for the quantity of reactive electric power ($E_{r\text{ alwn}}$) determined according to Section 11.4 at a price for 1 kVarh, equal to a [] per cent of the regulated public supply price for 1 kWh active electric power for the respective daytime zone and the respective voltage level.
- 11.6 The consumers under Section 10.3 pay an allowance for the quantity of reactive electric power released throughout the peak hours, determined according to the readings of the commercial metering devices, at a price for 1 kVarh, equal to the regulated public supply price for 1 kWh peak active electric power for the respective voltage level.
- 11.7 Whenever the consumers under Section 10.3 produce electricity and heat under combined generation cycle, they do not pay to the distribution system operator an allowance over the released reactive electric power produced under combined generation cycle.

12. Pricing of New Connections to the Distribution Network

- 12.1 The prices for customer connecting to the distribution network will be approved by ERE. These prices are paid by newly-connected consumers, existing consumers increasing their power, and by consumers-owners of power facilities (i.e. SPPs).
- 12.2 New electricity consumers pay the price for connecting to the distribution network, which includes only the direct expenses for connecting the installations of the consumers to the network of the electricity distribution company.
- 12.3 The prices of connecting consumers' facilities above **10 kVA** of contracted capacity are determined under an individual project and are formed through a calculation of the individual expenses on the project, including the expenses necessary for making the connection between the facility's installation and the nearest point of the respective network at which it is possible for the connection to be made.
- 12.4 The prices of connection are determined by groups of consumers, and include a constant component and a variable one, these being approved by the ERE.
- 12.5 The prices approved by the ERE for connecting are not subject to differentiation by levels of power between the lower and upper limit of power within the respective group.
- 12.6 The constant component is determined for the following minimum number of groups of consumers depending on the power of the consumer:
1. customer group of up to 6 kW;
 2. customer group of 7 to 15 kW;
 3. customer group of 16 to 50 kW;
 4. customer group of 51 to 100 kW;
 5. customer group of 101 to 200 kW;
 6. customer group of 201 to 500 kW;
 7. customer group of 501 to 1000 kW.

- 12.7 The distribution system operator is entitled to submit for the ERE approval of proposals for changing the groups of consumers.
- 12.8 The prices of connecting consumers whose power exceeds the maximum power set forth in Section 12.6 are determined on the grounds of individual projects.
- 12.9 The variable component is determined on the grounds of the distance from the facility to the nearest point of the network of the respective voltage, at which it is possible for the connection to be made, or to the nearest voltage-transformation station.
- 12.10 The variable component is equal to zero in those cases where the distance under Section 12.9 is less than or equal to 25 meters.
- 12.11 Apart from the cases under Section 12.10, each additional meter of cable or air line is paid for at the price for the respective group of consumers, this price being approved by the ERE.
- 12.12 The constant component of the prices of connecting is an expression of the average expenses for connecting a consumer belonging to a certain group and is determined through the following formula:

$$C_{pr}(i) = \frac{\sum_{1}^N S(i) \text{ (Expenses for connections in } i\text{-th group)}}{N}$$

where:

- $C_{pr}(i)$ = the price of connecting a consumer belonging to the i -th group of consumers, in ALL;
- $S(i)$ = expenses on connecting - the total expenses on connecting for the i -th group of consumers for the year preceding the year when the proposal for changes in prices was made, in ALL;
- N = the number of connections made for the i -th group of consumers for the preceding year.

- 12.13 The fixed component of the expenses on connecting comprises the following:

1. for the groups of up to 50 kW of connected power: the expenses on delivery and mounting the electrometer board, installing wiring for a distance of up to 25 meters, delivery and mounting the equipment needed for the specific purpose;
2. for the groups of 50 to 200 kW of connected power: the expenses on delivery and mounting the necessary equipment and wiring needed for the voltage-transformation station and the electrometer board, installing the wiring for a distance of up to 25 meters, delivery and mounting of the electrometer board and its equipment;
3. for the groups of 200 to 1000 kW connected power:

- a) the expenses needed for the voltage-transformation station in view of the power required, construction of the voltage-transformation station, its equipment with the necessary devices, wiring, delivery and mounting the apparatuses of the measuring system;
- b) the expenses on connecting the voltage-transformation station to the power distribution network of mean voltage by way installing an air line of 1 x 25 meters or a cable of 2 x 25 meters.

12.14 The variable component of the price of connection comprises the expenses on the installation of wiring for the distance from the nearest connecting point of the power distribution network of the respective level of voltage to the electrometer board of the consumer (for the groups of up to 200 kW of required power) or to the voltage-transformation station (for the groups of 200 to 1000 kW), decreased by the expenses for the 25 meters of wiring.

12.15 The above price determination is for a single line connection, or third level (III) of reliability of service for consumers. There are two other higher levels of security, Level II and Level I. The improved reliability is ensured through increased protection including multiple circuits into a customer's premise. This has to be consistent with the distribution code

12.16 The prices of connecting for other categories are determined as follows:

$$C_{pri} (II) = 1.8 * C_{pri} (III);$$

$$C_{pri} (I) = 2.8 * C_{pri} (III),$$

where:

$C_{pri} (III)$ is the price of connecting for the i -th group of consumers, third category of security;

$C_{pri} (II)$ - the price of connecting for the i -th group of consumers, second category of security, in ALL .;

12.17 $C_{pri} (I)$ - the price of connecting for the i -th group of consumers, first category of security, in ALL .

12.18 Connection charges for new generating facilities directly connected to the distribution system shall be established on a case-by-case basis. The connection charge should cover only the cost of the metering devices and lines that are built exclusively to connect a new generator to the network.

12.19 Assets financed through connection charges may not be included in the regulated asset base of the distribution system operator. Depreciation of these assets shall not be covered under use of network charges.

13. Deadlines

- 13.1 Based on this methodology, the distribution system operator shall submit to the ERE a request for the approval of new tariff no later than 6 months before the day that the new proposed tariffs are required to enter in force.
- 13.2 The distribution system operator shall submit to the ERE data on previous year costs and average tariff (prices) according to the sale structure, within April of the next year.
- 13.3 ERE shall examine these data within May of each year, and if deviations from the approved costs and tariff (prices) that impair the customers are evidenced, the ERE shall decide on the company reimbursements for the next year.

14. Transitional Provisions

- 14.1 The regulatory periods will be set in the ERE approved regulatory statement for implementation purposes of this tariff methodology.
- 14.2 The rates for the third regulatory period will be based on financial data in accordance with Uniform Standards of Accounting for regulatory purposes approved by ERE, and National Accounting and Reporting Standards/ IFRS.
- 14.3 For the first three regulatory periods, the targeted capital structure for the DSO will be as per the published ERE Regulatory Statement
- 14.4 The allowed after-tax return on equity will be initially set as per the published ERE Regulatory Statement.
- 14.5 For the initial regulatory periods,
 - (1) The distribution system operator tariff structure in the first regulatory will remain the same as it exists as of March 1, 2009.
 - (2) The distribution system operator may file an application to the ERE to revise the rate structure within the second or third regulatory period if the distribution system operator provides a rate design study based on customer usage patterns and cTSO of service for the various customer groups.
 - (3) The rates for each distribution service will be uniformly increased based on the increase of revenue requirements for the previous period.
- 14.6 The program for reduction and eventual elimination, to the extent possible, of energy losses are the responsibility of the distribution system operator. The ERE will set target reductions for energy losses within the regulatory periods. A study for the estimation of technical losses at each voltage level, will be provided by the licensee at the time of tariff application..

15. Final provisions

The Electricity Distribution Tariff Calculation Methodology was approved by ERE's Board of Commissioners by Decision Nr. 79, dated on June 26, 2008.

Part II: Application Form