CYPRUS ENERGY REGULATORY AUTHORITY (CERA)

THE LAWS REGULATING THE ELECTRICITY MARKET OF 2003 TO 2018, L.122(I)/2003

Regulatory Administrative Act No 359/2021

REGULATORY DECISION NO. 01/2021

Statement of Regulatory Practice and Electricity Tariffs Methodology

UNOFFICIAL TRANSLATION

Contents

1 Abbreviations and Definitions

1.1 For the purposes of this Regulatory Decision, the following definitions shall apply:

a. “RTBM” means the Real Time Balancing Market, i.e. the set of institutional, commercial and operational arrangements to manage balancing through the market. It is a market for the supply of Balancing Energy in real time (per real-time unit, specifically executed every 5 minutes), balancing supply and demand, taking into account all the conditions of the system in real time. Through the Real Time Balancing Market, Distribution Orders are issued which are addressed to the Balancing Service Providers in real time.

b. “Short-term marginal cost” means the marginal cost for a short period of time in which only operating costs can be differentiated since it is not considered feasible to make an investment and therefore the assets are considered as fixed.

c. “Interconnection line” means a transmission line, including the equipment and stations used for the interconnection of electrical systems, which crosses or bridges the border between Member States and which connects the transmission system or network of Cyprus with the national system or transport network of another Member State and/or the transmission system or network of a third country.

d. “Cross-border flow” means the natural flow of electricity in the transmission system of Cyprus resulting from the activity of producers and/or storage systems and/or customers located outside Cyprus.

e. “Interconnected system” means a system consisting of a number of transmission and distribution systems connected to each other by one or more interconnection lines.

f. “Interconnection Line Operator” means the legal person responsible for the operation, maintenance and, if necessary, development of the interconnection line, as well as the assurance of the long-term capacity of the interconnection line to meet the reasonable demand for the transfer and the cross-border flow of electricity and which will be authorized by CERA in accordance with the provisions of the Law of 2003 on the Electricity Market, as harmonized with Directive (EU) 2019/944.

g. “Distribution system operation” means the activity related to the management and operation of the distribution system.

h. “Transmission system operation” means the activity related to the management and operation of the transmission system, including system frequency management, trend management, congestion management and coordination of the planning and maintenance of the transmission network.

i. “Imbalance settlement” means the process by which participants in the wholesale electricity market receive or make payments for the deviations between their measured and authorized production or consumption of electricity on a part-time basis.

j. “ENTSO-E” means the European Network of Transmission System Operators established under Article 28 of Regulation (EU) 2019/943.

k. “Load Representative” has the meaning ascribed to it by the Electricity Market Rules.

l. “Ancillary service” has the meaning ascribed to it by the Law.

m. “Project of common interest” means a project necessary for the implementation of priority corridors and energy infrastructure zones set out in Annex I to Regulation (EU)

No 347/2013, which is included in the list of projects of common interest applicable throughout the Union, as set out in Article 3 of Regulation (EU) No 347/2013.

n. “Interconnection Line Owner” means the legal person who owns an interconnection line and holds a licence granted by CERA in accordance with the provisions of the Law of 2003 to 2018 on Electricity Market, as will be harmonized with Directive (EU) 2019/944.

o. “Ownership of the distribution system” means the activity related to the ownership of the distribution system.

p. “Ownership of the transmission system” means the activity related to the ownership of the transmission system.

q. “Regulation (EU) No 347/2013” means Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

r. “Long-term marginal cost” means a change in the total cost, which corresponds to a small change in quantity and is maintained for a long period.

s. “Long-term (flexible) power availability” means the long-term guarantee of availability of sufficient (flexible) power in the transmission system to meet in the long term the reliability criterion adopted for the electricity system.

t. “WACC” means the weighted average cost of capital, which corresponds to the weighted average cost of the sources of financing of an activity.

u. “Law” means the Laws Regulating the Electricity Market of 2003 to 2018, i.e. Laws 122(I)/2003 to 145(I)/2018, as amended and replaced from time to time.

v. “Cost-effectiveness” means the maximization of social well-being over time, which includes concepts such as distributive profitability, which achieves the optimal distribution of goods and services, and productive profitability, which can be used to avoid further outputs of goods and services for a given set of inputs.

w. “Marginal cost” means a change in the total cost corresponding to a small change in the quantity of production, demand, network usage, etc.

x. “DAM” means the Day Ahead Market, that is the Energy spot market organized by an auction process, matching once a day supply and demand curves and thus fixing prices in an anonymous, yet transparent and secured manner. The Day Ahead Market is managed by the Market Operator

y. “Forward Market” is the Energy market where trading is carried out on a bilateral basis (over-the-counter), namely with Bilateral OTC Contracts with obligation of physical delivery (production and offtake).

z. “Supply” has the meaning ascribed to it by the Law.

aa. “CERA” means the Cyprus Energy Regulatory Authority, which, inter alia, is responsible for the economic regulation of activities within the electricity sector.

bb. “RAB” means the Regulated Asset Base, i.e. the net book value of the regulated assets of an organization used exclusively for the provision of regulated services.

cc. “Participants” means the entities described in the Electricity Market Rules.

dd. “Distribution system” has the meaning ascribed to it by the Law.

ee. “Transmission system” has the meaning ascribed to it by the Law.

ff. “Project implementation body” means the TSOC or other operator or investor who has legal personality under applicable national law and is active in the implementation of a project of common interest.

gg. “Wholesale electricity market” means the whole of the forward market, the day ahead and/or the intra-day market through which purchases and sales of electricity are made by the Participants.

hh. “PCI 3.10.2 Euroasia Interconnector” means the electrical interconnection between Kofinou (Cyprus) and Korakia (Crete, Greece) which is the project of common interest under number 3.10.2.

2 Electricity market organization in Cyprus

2.1 The electricity market in Cyprus has been organized in separate sectors that need to be licensed by CERA, as follows:

a. The electricity generation sector, which is a competitive sector of activity with freedom of entry into the market, as long as the relevant authorization has been granted by CERA. The generation of electricity from a dominant company shall be regulated with the aim of protecting customers and facilitating entry into the market until CERA decides that regulation is no longer appropriate.

b. The activity of the ownership of the transmission system shall be a regulated monopoly activity.

c. The activity of the operation of the transmission system shall be a regulated monopoly activity.

d. The activity of the ownership of the distribution system shall be a regulated monopoly activity.

e. The activity of the operation of the distribution system shall be a regulated monopoly activity.

f. The electricity supply activity is a competitive activity. All customers have the option to choose their supplier and there is freedom to enter the supply, as long as the relevant authorization has been granted by CERA. The supply of electricity from a dominant company shall be regulated in order to protect the interests of customers and facilitate entry into the market until CERA decides that the regulation is no longer appropriate. The supply from any supplier is regulated in terms of how certain charges imposed on the supplier are passed on to customers.

2.2 Furthermore, the Treaty on the Functioning of the European Union maintains the Trans-European Transmission Networks, the Trans-European Energy Networks and the Trans-European Telecommunications Networks with the aim of connecting all regions of the European Union. These networks were created to contribute to the development of the internal market and employment, as well as to the achievement of the objectives for the environment and sustainable development.

Projects of Common Interest (PCIs) are cross-border infrastructure projects that connect the energy systems of the countries of the European Union, i.e. the Trans-European Energy Networks. They aim to provide assistance to the European Union in order to achieve its energy policy and energy and climate objectives, an affordable economy, safe and sustainable energy and long-term decarbonization of the economy in accordance with the Paris Agreement.

Regulation (EU) No 347/2013 lays down the guidelines for the timely development and interoperability of corridors and priority zones of trans-European energy infrastructures, namely PCI infrastructures connecting the European Union and one or more third countries and relating to electricity, natural gas, oil and carbon dioxide.

Pursuant to Article 3(4) ofRegulation (EU) No 347/2013, the European Commission is entrusted with the power to adopt delegated acts establishing the list of projects of common interest of the European Union ("Union list"). A new Union list shall be drawn up every two years. So far, four Union lists have been issued.

The Republic of Cyprus has been promoting three PCIs since 2013. Two gas PCIs in the Southern Gas Corridor ("SGC"), "CyprusGas2EU" and "EastMed Pipeline" and one electricity PCI in the North-South Electricity Interconnections in Central and Southeastern Europe ("NSI East Electricity"), the EuroAsia Interconnector.

The implementation of energy infrastructures for electricity transmission projects related to the PCIs will help to remove the energy isolation of Cyprus through the interconnection of the island with the Trans-European Energy Networks. At the same time, it will contribute to the achievement of the targets of the Energy Union for 2030, energy security, integration of the EU internal energy market, reduction of carbon emissions, diversification of energy sources and achieving a 15% electricity interconnection target by 2030 (EuroAsia Interconnector PCI).

The electrical interconnection entitled 'EuroAsia Interconnector' consists of the electrical interconnection of the electricity transmission systems of the states of Israel, Cyprus and Greece (Crete) with DC submarine cables and onshore HVDC converter stations at each connection point and has a total capacity of 2000 MW. The project is an energy bridge between the two continents, with a total interconnection length of about 1,208 km and creates a reliable alternative power corridor from the Eastern Mediterranean to Europe. The company EuroAsia Interconnector Limited was designated by the European Commission as the Project Promoter of the PCI, following a recommendation from the Government of Cyprus (Ministry of Energy, Commerce, Industry and Tourism) and the Greek Government (Ministry of Environment, Energy and Climate Change). Since 2013, the project has been included in the list of projects of common interest of the European Union in the form of a cluster of PCIs consisting of the following sub-projects:

• PCI 3.10.1 - Interconnection between Hadera (Israel) and Kofinou (Cyprus)

• PCI 3.10.2 - Interconnection between Kofinou (Cyprus) and Korakia Crete (Greece)

It is noted that, by decision of the Greek Government, the internal line interconnecting Korakia Crete (Greece) and Attica (Greece) is now being implemented as a National Project by the Hellenic Republic, while ensuring the issues of interoperability and interconnectivity with the PCI Euroasia Interconnector.

In the context of the examination of the investment request submitted by the Project Promoter of the PCI 3.10.2 to the involved national regulatory authorities, RAE and CERA, which on 10 October 2017 resulted in a Cross-Border Cost Allocation Agreement as follows:

- Project of Common Interest No. 3.10.2 “Interconnection between Kofinou (CY) and Korakia, Crete (EL)”, has reached a sufficient degree of maturity for decision-making purposes;
- the cost sharing between the two Member States is reasonable and documented and there is a clear positive impact from the project results on the parties involved;
- for Step 3 (Cyprus-Crete) of project No 3.10.2 Interconnection between Kofinou (CY) and Korakia, Crete (EL) the Republic of Cyprus will bear 63% of the project implementation costs and the Hellenic Republic 37%, meaning that the project will be subsidized by 50% from European funds.

2.3 The purpose of this Statement of Regulatory Practice and Methodology of Establishing Electricity Tariffs is to regulate:

a. the manner in which CERA will determine the allowed revenue for each regulated activity; and

b. the manner in which the regulated tariffs will be determined;

c. the manner in which a Transparency Framework for the Establishment of the Weighted Average Cost of Capital, which has already been included in the terms of the Cross-Border Cost Sharing Agreement for Project 3.10.2, will be determined; and

d. in a transparent manner, the allowed revenue of the Implementing Body or, subsequently, of the Interconnection Line Operator that arise for the purposes of project 3.10.2.

3 Objectives of the regulation of electricity tariffs and the charge for the use of the PCI 3.10.2 interconnection

3.1 The primary objectives of the regulation of tariffs are to maximize the long-term competitiveness of the Cypriot economy, to protect the interests of customers in the short and long term against monopoly-based prices, to serve public service obligations, to ensure energy supply and to promote energy efficient and quality services provided by License Holders. Tariffs shall be established on the basis of a methodical and consistent application of the principles included in the methodology and the proposals and decisions of tariffs shall be based on documented data and shall be established after in-depth consultation with the parties involved.

3.2 More specific objectives of regulated tariffs are:

a. to reflect the cost of the service so as to enhance financial efficiency;

b. to allow for the reasonable prospect of recovering costs incurred on an efficient basis;

c. to be fair and non-discriminatory among customers, unless justified by other tariff objectives, such as enhancing economic efficiency;

d. to avoid interference between different activities in the electricity sector (i.e. production, ownership of the transmission system, management of the transmission system, ownership of the distribution system, operation of the distribution system and supply or other unregulated activities);

e. to be simple, transparent and predictable;

f. to encourage efficient consumption by customers;

g. to be compatible with the clear environmental objectives set by the Republic of Cyprus;

h. to allow for the recovery of cost incurred on an efficient basis in relation to public utility obligations and the promotion of electricity generation from renewable energy sources and high-efficiency cogeneration;

i. to encourage the safeguarding of energy supply;

j. to provide incentives to regulated companies to operate efficiently; and

k. to promote the efficiency and quality of the services provided by License Holders.

3.3 In addition to the above objectives, the basic principles set out in the Union and national framework, which comply with the charge for the use of the PCI 3.10.2 interconnection, include:

a. the protection of the users of the Interconnection Line, so that the charges for the use of the Interconnection Line imposed on users (producers) reflect the net positive benefit they enjoy from using the interconnection line,

b. compliance with the principles of transparency and non-discrimination,

c. facilitating the efficient long-term development and operation of the pan-European interconnected system and the efficient operation of the pan-European electricity market,

d. the principles of the law on cross-border exchanges in electricity, thus enhancing competition within the internal market for electricity, taking into account the particular characteristics of national and regional markets, including the establishment of a compensation mechanism for cross-border flows of electricity, the setting of harmonised principles on cross-border transmission charges and the allocation of available capacities of interconnections between national transmission systems,

e. the fundamental principles for orderly, integrated electricity markets, which allow non-discriminatory market access for all energy suppliers and customers, strengthening of the position of consumers, ensuring competitiveness on the world market and demand response, energy storage and energy efficiency, facilitating the concentration of distributed demand and supply, and enabling the integration of the market and the sector and market-based compensation of electricity generated from renewable sources,

f. defining in a transparent manner the allowed revenue of the Implementing Body or, subsequently, of the Interconnection Line Operator, to be used for the operation and maintenance of the Interconnection Line of PCI 3.10.2 Euroasia Interconnector,

g. defining clearly the allowed revenue of the Implementing Body or, subsequently, of the Interconnection Line Operator or Interconnection Line Owner (in case the separation is deemed appropriate), to be used for the implementation of PCI 3.10.2 Euroasia Interconnector.

4 Institutional framework for the use of the interconnection line

4.1 The Statement of Regulatory Practice and Methodology of Establishing Electricity Tariffs was designed based on the following documents:

a. Regulation (EU) No 838/2021 of the European Parliament and of the Council of 23 September 2010 on laying down guidelines relating to the inter-transmission system operator compensation mechanism and a common regulatory approach to transmission charging.

b. Regulation (EU) No 347/2013 of the European Parliament and of the Council of 17 April 2013 on guidelines for trans-European energy infrastructure and repealing Decision No 1364/2006/EC and amending Regulations (EC) No 713/2009, (EC) No 714/2009 and (EC) No 715/2009.

c. Regulation (EU) 2015/1222 of the European Parliament and of the Council of 24 July 2015 establishing a guideline on capacity allocation and congestion management.

d. Regulation (EU) 2016/1719 of the European Parliament and of the Council of 26 September 2016 establishing a guideline on forward capacity allocation.

e. Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal electricity market.

f. Directive (EU) 2012/27 / EC of the European Parliament and of the Council of 25 October 2012 on energy efficiency, and Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency.

g. Directive (EU) 2018/2002 of the European Parliament and of the Council of 11 December 2018 amending Directive 2012/27/EU on energy efficiency.

h. Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2009/72/EU.

i. The Laws Regulating the Electricity Market of 2003 to 2018 (Law 122(I)/2003 - Law 145(I)/2018)

j. The Laws on the Regulation of the Electricity Market (Electricity Pricing Procedures) of 2004, Regulatory Administrative Act No 472/2004.

k. The Citizens' Energy Forum guidance on good practice in energy billing (MEMO/09/429).

l. The Energy Efficiency Laws of 2009 to 2015 (Law 31(I)/2009, Law 53(I)/2012, Law 56(I)/2014, Law 149(I)/2015).

m. The Laws on the Promotion of Energy Efficiency in Heating and Cooling and Heat and Power Cogeneration of 2006 to 2015 (Law 174(I)/2006, Law 150(I)/2015).

n. CERA Decision No 216/2017 of 10 October 2017 on the Cross-Border Cost Allocation of the PCI No 3.10.2 Interconnection Between Kofinou (CY) and Korakia, Crete (EL) and No 3.10.3 Internal Line Between Korakia , Crete and Attica Region (EL).

o. CERA Decision No 136/2021 of 23 April 2021 on the Update of the Cross-Border Cross-Border Cost Allocation of the PCI No 3.10.2 Interconnection Between Kofinou (CY) and Korakia, Crete (EL).

Directive (EU) 2019/944

4.2 Directive (EU) 2019/944 lays down common rules for the internal electricity market and repeals Directive 2009/72/EC.

4.3 The Directive lays down, inter alia, the following:

a. The regulatory authorities shall be responsible for fixing or approving sufficiently in advance of their entry into force at least the national methodologies used to calculate or establish the terms and conditions for:

   i. connection and access to national networks, including transmission and distribution tariffs or their methodologies. Those tariffs or methodologies shall allow the necessary investments in the networks to be carried out in a manner allowing those investments to ensure the viability of the networks;

   ii. the provision of ancillary services which shall be performed in the most economic manner possible and provide appropriate incentives for network users to balance their input and off-takes, such ancillary services shall be provided in a fair and non-discriminatory manner and be based on objective criteria;

b. With a view to increasing transparency in the market and providing all interested parties with all necessary information and decisions or proposals for decisions concerning transmission and distribution tariffs, regulatory authorities shall make publicly available the detailed methodology and underlying costs used for the calculation of the relevant network tariffs, while preserving the confidentiality of commercially sensitive information.

c. Member States shall create appropriate and efficient mechanisms for regulation, control and transparency so as to avoid any abuse of a dominant position, in particular to the detriment of consumers, and any predatory behaviour.

Regulation (EU) 2019/943

Regulation (EU) 2019/943 aims to:

a. set the basis for an efficient achievement of the objectives of the Energy Union;

b. set fundamental principles for well-functioning, integrated electricity markets, which enable market and sectoral and market integration;

c. set fair rules for cross-border exchanges in electricity, thus enhancing competition within the internal market for electricity, taking into account the particular characteristics of national and regional markets, including the establishment of a compensation mechanism for cross-border flows of electricity, the setting of harmonised principles on cross-border transmission charges and the allocation of available capacities of interconnections between national transmission systems;

d. facilitate the emergence of a well-functioning and transparent wholesale market, contributing to a high level of security of electricity supply, and provide for mechanisms to harmonise the rules for cross-border exchanges in electricity.

4.5 Regulation (EU) 2019/943 sets out, inter alia, the following:

a. Charges applied by network operators for access to networks, including charges for connection to the networks, charges for use of networks, and, where applicable, charges for related network reinforcements, shall be cost-reflective, transparent, take into account the need for network security and flexibility and reflect actual costs incurred insofar as they correspond to those of an efficient and structurally comparable network operator and are applied in a non-discriminatory manner.

b. The method used to determine the network charges shall neutrally support overall system efficiency over the long run through price signals to customers and producers and in particular be applied in a way which does not discriminate positively or negatively between production connected at the distribution level and production connected at the transmission level.

c. Tariff methodologies shall reflect the fixed costs of transmission system operators and distribution system operators and shall provide appropriate incentives to transmission system operators and distribution system operators over both the short and long run, in order to increase efficiencies, including energy efficiency, to foster market integration and security of supply, to support efficient investments, to support related research activities, and to facilitate innovation in interest of consumers in areas such as digitalisation, flexibility services and interconnection.

The Laws Regulating the Electricity Market

4.4 The Law Regulating the Electricity Market of 2003 (Law 122(I)/2003) and all its amendments concerning the regulation of the electricity market in the Republic.

The Laws on the Regulation of the Electricity Market (Electricity Pricing Procedures) of 2004, Regulatory Administrative Act No 472/2004.

4.5 The Laws on the Regulation of the Electricity Market (Electricity Pricing Procedures) of 2004, Regulatory Administrative Act No 472/2004 refer to the procedures followed and to the consultations carried out to determine the pricing and charges of the companies/license holders operating in the electricity market.

Directive (EU) 2012/27/EU on energy efficiency, along with the amendment to Directive (EU) 2018/2002

4.6 Directive 2012/27/EU, along with the amendment to Directive (EU) 2018/2002, establishes a common framework of measures to promote energy efficiency, including the requirements for the provision of pricing information to end customers.

4.7 Articles 9, 10, 11, 15 and Annex VII to the Directive set out, inter alia, issues relating to the measurement and pricing of individual consumption.

Specifically with regard to tariffs, Article 15 sets out the following:

a. Member States shall ensure the elimination of incentives in the transport and distribution tariffs resulting from the total efficiency (including energy efficiency) of the electricity generation system or those which may impede the participation of response in demand, in the balancing markets and in the provision of ancillary services;

b. Member States shall ensure that pricing enables suppliers to improve the participation of customers in the efficiency of the system, including response to demand in accordance with national conditions.

c. Member States shall ensure that the regulation and tariffs of the system meet the energy efficiency criteria set out in Annex XI to that Directive, taking into account the guidelines and codes drawn up in accordance with Regulation (EC) No 714/2009 on network access conditions for cross-border exchanges of electricity.

5 Allowed revenue

5.1 CERA will determine the allowed revenue in accordance with the regulatory review and in accordance with the objectives set out in paragraphs 3.1 and 3.2, for each of the activities of a dominant producer, the ownership of the transmission system, the operation of the transmission system, the ownership of the distribution system, the operation of the distribution system and the supply by a dominant supplier.

5.2 The regulatory review period for each regulated activity shall be that set out in Annex 4.

5.3 Before the start of each regulatory review period, CERA shall carry out a regulatory examination to determine the allowed revenue of each activity for that regulatory period.

The objective of the regulatory review will be to motivate the provider of each regulated activity to reduce the controllable costs, while allowing the activity provider a reasonable prospect of recovering the costs in order to maintain a viable efficient business. The provider of a regulated activity will be rewarded for any positive performance achieved in the reduction of controllable costs or will be charged with the total cost of each negative performance, in accordance with the provisions of Annex 3 to this Regulation. The review of the implementation of the incentives to reduce the controllable operating costs will be carried out on an annual basis and the reduction of the controllable costs will not be transferred as an ex-post adjustment to the allowed revenue of the current or subsequent regulatory review period, except as provided for in the adjustment of the K factor described in paragraph 6.4. It is understood that allowed revenue arising from non-controllable operating costs (as defined in Annex 3) will be adjusted where there are differences in forecasts or factor variations.

5.4 The authorized revenue for each activity referred to in paragraph 5.1, with the exception of supply from a supplier with a dominant position, will include a capital part and an operating part, as follows:

a. The capital part of the allowed revenue will include the depreciation of the fixed assets included in the RAB and the allowed return on the average RAB. The return on RAB shall be determined in accordance with Annex 1. The allowed return on RAB shall correspond to the Weighted Average Cost of Capital (WACC), which will be determined in accordance with Annex 2.

b. The operating part of the allowed revenue shall be determined in accordance with Annex 3.

5.5 The allowed WACC for an activity will be determined in the context of the periodic regulatory review in accordance with Annex 2 on the basis of factual data and will be a nominal rate of return. During the periodic regulatory review, CERA may decide to index the WACC or the data used to determine the WACC in such a way that the WACC varies during the regulatory review period. The objective of this indexation is to protect the activity which undertakes the regulated activity from uncontrolled changes in its financing costs.

5.6 The RAB for an activity shall be calculated at the end of each year in accordance with Annex 1, and there shall be an ex-post adjustment in the capital part of the allowed revenue based on the actual capital expenditure of the year included in the RAB. If the capital expenditure is higher than budgeted, the difference shall be transferred to the prices only to the extent that CERA considers the excess to be reasonable. The ex-post adjustment shall be applied to the tariffs of the next year in the regulatory review period and shall adjust the projected capital part of the allowed revenue for the remaining regulatory review period. At the end of each year, each regulated activity must submit to CERA detailed statements containing the following information:

- the actual capital expenditure of the reporting year;
- a comparison of the actual capital expenditure with the capital expenditure included in the budgeted RAB and approved by CERA;
- information on the reasons for diversification, whether positive or negative.

If the regulated activity has made or plans to make capital expenditure which was not included in the RAB and which it considers that must be included in the RAB, it is obliged to submit to CERA a reasoned request for approval of the inclusion of each expenditure in the RAB. Without the appropriate approval of CERA, it shall not have the right to include such expenditure in the RAB of the activity.The above shall also apply if the regulated activity incurs significant capital expenditure/investments that have not been approved for inclusion in the RAB.

The first years of the new regulatory review period shall include adjustments of the last years of the first regulatory review period.

5.7 The operating part of the allowed revenue shall be adjusted in accordance with Annex 3 and, where appropriate, in accordance with the methodology for adjusting the price of fuel described in paragraph 7.12.

5.8 The allowed revenue for each activity shall take into account customer contributions so that the activity is not overcompensated.

5.9 The allowed revenue for the supply by a dominant supplier shall be determined in accordance with paragraph 7.54 and 7.55 to cover the reasonable cost of managing the business (including depreciation) plus a allowed mark-up on the reasonable cost of managing the business.

5.10 CERA shall adopt a decision establishing a methodology regarding the budgeted and ex-post adjustments on allowed revenue within the regulatory review period and the relevant timetables for the regulated activities to report to CERA.

5.11 CERA reserves the right, at its discretion, to make significant variations in the electricity market during the regulatory review period, to make amendments and to request variations or to approve a variation in allowed revenue and tariffs (including the structure of tariffs) for electricity, with the aim of ensuring the proper functioning of the market in the context of healthy competition for the benefit of customers, in accordance with the Law.

5.12 In relation to PCI 3.10.2 Cyprus-Crete interconnection line, the allowed revenue shall be calculated on the basis of components relating to the projected maintenance and operating costs (OPEX) plus a return to the RAB and depreciation on the average RAB. The approved weighted average cost of capital (WACC) of the Cyprus-Crete interconnection line, including an amount as a WACC premium, shall be based on the current conditions and is laid down in the RAE-CERA Agreement on the Cross-Border Cost Allocation for the PCI No 3.10.2 Interconnection between Kofinou (CY) and Korakia, Crete (EL) dated 10 October 2017 and updated on 23 April 2021**.** In case of significant changes in the current conditions, the already approved WACC may be differentiated with respect to Cyprus and provided that the prior approval of CERA is ensured. The terms regarding the duration of depreciation for PCI 3.10.2 shall be determined by CERA and may differ from the terms of the remaining investments in accordance with Regulation (EU) 347/2013, as the Crete-Cyprus interconnection line is part of the European projects of common interest and is regarded as a project of major importance for Cyprus, with a cross-border impact and particularly positive effects at national, regional and Union level, with a longer useful life and a higher degree of risk in terms of its implementation, construction, operation and maintenance, compared to the other investments.

6 General structure of electricity tariffs

6.1 Tariffs for goods or services provided through a regulated activity shall be regulated and, for the avoidance of any doubt, all tariffs to end customers served by a supplier regulated in accordance with paragraph 2.1(f) shall be regulated in accordance with the objectives set out in paragraphs 3.1 and 3.2 and the principles set out in the paragraph 6.13.

6.2 The provider or the statutory operator of a regulated product or regulated service shall apply a tariff applicable to the product or service provided. Before the year in which the tariff is applied, the provider or the statutory operator shall propose the tariff to CERA. CERA shall examine the tariff against the targets set out in the paragraphs 3.1 and 3.2 and decide whether to approve or request an amendment to the proposal. A conciliation between two or more targets may be required when considering the tariff.

6.3 The regulated tariffs for one year shall be determined in such a way as to recover such year's allowed revenue for the regulated generation activity, ownership of the transmission system, operation of the transmission system, ownership of the distribution system, operation of the distribution system and supply.

6.4 The allowed revenue to be recovered through the regulated network tariffs (T-NH, T-NM, T-NL) and the regulated production tariff (T-W) shall include an adjustment factor K to be calculated for each tariff separately on an annual basis to take account of the positive or negative deviation in the recovery of allowed revenue in the previous year due to reasonably non-controllable energy demand forecast errors.

6.5 The adjustment factor K shall be calculated by the provider or the statutory operator of the regulated service, and the calculation will be reviewed and approved by CERA.

6.6 The adjustment factor K shall be calculated on the basis of the total energy exported in the case of the production tariff (T-W) and on the basis of the corresponding measured energy demand of customers in the case of each network tariff (T-NH, T-NM, T-NL). The adjustment factor K may be lower or higher than 1. The adjustment factor K may include an interest provision, which shall be approved by CERA.

6.7 In the case of use of the Cyprus-Crete interconnection line (PCI 3.10.2), a charge shall be imposed on the users (producers) of the line which shall benefit the Interconnection Line Operator (currently the Implementing Body).

6.8 The tariff categories, as well as the charge for the use of the interconnection line, shall be determined according to the following Table 1 of this Statement of Regulatory Practice and Electricity Tariffs Methodology.

Table 1: Categories of tariffs

Description	Tariffs
T-W	Wholesale electricity tariff, which is imposed on the sale of electricity produced by the regulated activity through Bilateral Contracts to any activity (regulated or unregulated)
T-NH	Tariff for the use of the Transmission System (36kV or more)
T-NM	Tariff for the Use of Distribution System (medium voltage: greater than 1kV and less than 36kV), which includes a charge component related to the DSO
T-NL	Tariff for the Use of Distribution System (low voltage: at or below 1kV), which includes a charge component related to the DSO
T-BM	Tariff for Business Management Services provided to customers (invoicing, etc.)
T-AS	Tariff for the provision of Ancillary Services
T-PSO	Tariff for the recovery of expenses of PSOs
T-TSO	Tariff for the recovery of expenses of the Transmission System Operator of Cyprus (TSOC)
T-MET	Tariff for the recovery of expenses of meter-readings incurred by the Distribution System Operator (for users connected to the Distribution System)
T-RET	Supply tariffs and electricity market charges to the end consumer
T-CS	Competitive cost tariff of regulated supply company for the supply of electricity to customers
T-ILU	Tariff for the use of the interconnection line

6.9 The following tariffs charged to suppliers will be regulated: T-AS, T-MET. The following tariffs shall be charged to the suppliers and shall only be regulated when imposed by a producer regulated in accordance with paragraph 2.1(a): T-W

6.10 A supplier that does not hold a dominant position shall be free to decide how to transfer the cost of T-AS, T-MET and the cost of electricity supplied through the Wholesale Electricity Market and/or through the Deviations Clearing Mechanism and any other costs incurred under the Electricity Market Rules to end users in accordance with the principles set out in paragraph 6.13.

6.11 The following tariffs charged to Load Representatives shall be regulated and suppliers shall pass on the charges to their customers: T-NH, T-NM, T-NL, T-PSO, T-TSO.

6.12 The following tariffs imposed on final customers shall not be regulated unless they are imposed by a supplier regulated in accordance with paragraph 2.1(f): T-BM.

6.13 Customer tariffs may vary by customer category depending on the characteristics related to cost, but may not vary based on the customer's geographical location within Cyprus.

7 Tariff methodology

7.1 The tariff methodology applies to regulated tariffs. All regulated tariffs shall meet the targets set out in the paragraphs 3.1 and 3.2 and, in addition, all tariffs imposed on customers shall comply with the principles set out in paragraph 6.13.

7.2 Certain parameters to be used in the determination of tariffs shall be determined from time to time by CERA. The initial values of the parameters are set out in Annex 4.

7.3 As regards T-W, T-NH, T-NM, T-NL, T-CS, T-RET, the provisions of Annex XI to Directive 2012/27/EC and its amendment for energy efficiency shall apply.

7.4 As regards the tariffs for the use of the Transmission System and the Distribution System (T-NH, T-NM, T-NL), the following general principles for determining the charges shall apply:

- The tariffs shall apply exclusively to the loads (consumption) of the Transmission System and the Electricity Distribution System of Cyprus. Units of production as well as storage units of electricity "upstream of the metre" shall be exempted from these tariffs.
- In the case of a final user with on-site production (self-production), the tariffs shall be applied as regulated by the relevant CERA Decisions, in accordance with the provisions hereof (in particular paragraphs 7.16 to 7.44).
- Electric vehicle charging facilities shall be subject to the same regulations applicable to consumers of the Cyprus Electricity Distribution System.

7.5 As regards the tariffs for the use of the Distribution System (T-NM, T-NL), the total annual allowed revenue PR_{DS} for the Distribution System shall be allocated to the part concerning the Medium Voltage Network (MT), EE_{MT}, and the remainder that involves the Low Voltage Network (LV), EE_{XT} ($EE_{\Delta\Delta} = EE_{MT} + EE_{XT}$), with an allocation key d (%), (% of the total revenue for each voltage level - MT and XT), so that: $EE_{MT} = EE_{\Delta\Delta} \times d(\%)/100$ και $EE_{XT} = EE_{\Delta\Delta} \times (100-d(\%))/100$. The allocation key shall be determined by the DSO on the basis of a relevant study to be prepared and updated prior to the start of each regulatory review period. This study should distinguish the costs relating to each MV or LV network (e.g. based on the assets of each MV or LV network for depreciation and return, the corresponding transit fees, the corresponding new investments, etc.) and allocate common costs (e.g. payroll, administration costs, etc.) with appropriate allocation keys for each expenditure category, in order to obtain in the end the final allocation key d (%) of the total annual allowed revenue.

T-W: Wholesale electricity tariff

7.6 T-W is the wholesale electricity tariff. T-W shall apply to all sales of electricity by dominant producers, with the exception of energy sold by them through the Day Ahead Market and the Intra-Day Market (if any), the Balancing Energy provided during the operation of the Real Time Balancing Market, the ancillary services contracts with the TSOC and the long-term reserve contracts with the TSOC. To avoid doubts, T-W shall apply to the sale of electricity by all regulated producers through Bilateral Contracts to any activity (regulated or unregulated). Also, it is clarified that initially all regulated producers are allowed to sell electricity through Bilateral Contracts only to regulated suppliers. The possibility of regulated producers to sell electricity to non-regulated suppliers through Bilateral Contracts may be authorized by a future decision of CERA.

7.7 The wholesale electricity tariff T-W shall form the basis for regulated contracts between the dominant producer and other participants as a range of products may be offered by the dominant producer. The relevant procedures shall be regulated by CERA and different products shall be priced at different prices. The tariff for the supply of electricity shall be based on the corresponding T-W.

7.8 Except as provided for in paragraph 7.9, T-W shall be determined in such a way as to allow the regulated cost of the regulated producer to be recovered, minus net revenue from:

a. the sale of electricity from conventional power plants and renewable energy plants via the Day Ahead Market;

b. the provision of Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR) or other types of reserves in the Integrated Scheduling Process (ISP);

c. the provision of Balancing Energy in the Real Time Balancing Market;

d. the provision of a Replacement Reserve, if required;

e. the provision of a Contingency Reserve, if required;

f. the provision of a Black Start service, if required;

g. the provision of Emergency Energy beyond its Registered Capacity, if required;

h. the provision of Contingency Availability Reserve for the Contracted Production Units, if required;

i. the requirement to synchronize the Generating Units and the Contracted Units by executing a Commitment Instruction resulting from the Integrated Scheduling Process (ISP), if required;

j. the purchase of electricity from third-party producers with conventional units;

k. the purchase of electricity from RES producers outside the National Subsidy Plans;

l. any other category of revenue arising in the future under the provisions of the Electricity Market Rules.

The above categories of revenue do not include Non-Compliance Charges that may be imposed on the regulated producer as well as the cost of clearing the non-mandated deviations as a result of its participation in the Wholesale Electricity Market and the Real Time Balancing Market, based on the applicable provisions of the Electricity Market Rules. Consequently, the costs arising from the imposition of Non-Compliance Charges to the regulated producer as well as the costs resulting from the liquidation of the non-mandated deviations are irrecoverable and are entirely borne by the regulated producer. The values of the net revenue of categories (j) and (k) are initially not included in the categories of net revenue that will contribute to the recovery of the regulated cost of the regulated producer. It is clarified that this is interpreted as no purchase (and subsequent sale) of energy for the categories referred to in points (j) and (k) is initially authorized by the regulated producer. The inclusion of the above categories of net revenue (items (j) and (k)) in the total income contributing to the recovery of the regulated cost of the regulated producer will be made in the future by a relevant decision of CERA. For the implementation of the above provision, the use of a factor A, which multiplies items (j) and (k) shall be used. The factor A is initially set to zero (0) and, upon a future decision of CERA, it is likely to receive a value equal to one (1). For the avoidance of doubt, any of the elements of net income of the above categories (a) - (l) may receive positive or negative values.

7.9 A regulated producer may propose a discount which is expected to lead to less revenue recovery from those provided for in paragraph 7.8. CERA, when considering whether to approve such a proposal, will take into account the impact of the proposed price on competition in the production and supply markets.

7.10 T-W shall be determined and made public before the start of the valuation year and shall be calculated for each half hour of the valuation year in accordance with the following principles:

a. T-W shall be determined in such a way that it is possible to recover the Allowed Revenue for the regulated generation activity, less the net income in accordance with the provisions of paragraph 7.8.

b. T-W shall reflect the system's marginal energy and power costs, with an adjustment for the recovery of the allowed generation activity revenue, with the exception of the provisions of paragraph 7.9.

c. The limit energy cost and the system power limit cost are calculated by the TSOC. The short-term limit energy cost shall be estimated for each half hour of the following year based on a simulation of the market of the Cypriot energy system incorporating the maximum possible set of data and technical limitations on the operation of the production units and the System, as these are taken into account in the resolution of the Integrated Scheduling Process, taking into account uncertainties, for example, in the availability of production units and in demand and taking the budgeted fuel prices as the basis for calculating the variable costs of conventional production units. The marginal power generation cost (and the voluntary demand-side response, if applicable) shall be estimated for each half hour of the following year on the basis of a relevant reliability study of the Cypriot electricity system. The TSOC shall be responsible for setting up the methodologies to calculate the limit energy and system power limit costs for each half hour of the following year and shall submit the proposed methodologies to CERA for approval.

d. The values of these elements (limit energy costs and limit system power costs for each half hour of the following calendar year) shall be made public by the TSOC and shall then be provided to each regulated producer for the calculation of the T-W proposed by them, by applying the analytical methodology presented in Annex 5.

e. The calculation and publication of the limit energy costs and limit power costs by the TSOC for every half hour of tariff year Y should be completed by 31 August of year Y-1.

f. The adjustment for the recovery of the allowed revenue of the regulated generation activity shall be applied uniformly to the production at all half-hours of the year, unless the producer to whom the tariff is applicable proves satisfactorily to CERA that an alternative adjustment which varies by half-hour will better reflect the objectives of the tariff set out in the paragraph 3.2.

g. The half-hours of the year with similar limit energy and power costs will be grouped by the regulated producer and a single limit cost (weighted average limit cost by volume) shall be applied for such a group of hours. In order to make it clearer, T-W does not need to be differentiated for the 17,520 half-hours within the tariff year and can, for example, be differentiated by season, day/night, day of the week/weekend or public holidays within the year. The tariff adjustment proposal by the regulated producer shall include the proposed half-hour group selection.

7.11 The detailed methodology for calculating T-W is presented in Annex 5.

7.12 T-W shall be adjusted within the year of valuation according to a fuel price adjustment, based on the following:

a. The purpose of calculating the fuel price adjustment is to allow the regulated producer to recover reasonable non-controllable changes in the cost of fuel used by its power plants for the production of electricity.

b. At the beginning of each regulatory review period, the Basic Fuel Price shall be set at a fixed price, which shall be approved by CERA for the entire years of the regulatory review period.

c. Before the start of each tariff semester and no later than 31 October of year Y-1 (for the first half of the year Y) and on 30 April of year Y (for the second half of year Y), the regulated producer shall propose the fuel clause factors for the adjustment of the T-W tariff that will be applicable for the months of the respective semester. CERA shall examine the proposal and decide whether to approve or reject the fuel clause factors.

d. The fuel adjustment (in €/kWh) shall be calculated by the regulated producer on a monthly basis, as the deviation of the Average Fuel Cost from the Basic Fuel Price adjusted to the fuel clause factor and shall apply to the regulated producer’s charges for the sale of energy.

7.13 The adjustment of K factor for T-W shall be calculated by the regulated producer and the calculation shall be reviewed and approved by CERA. This adjustment is intended to protect the regulated producer and electricity customers from the impact of non-controllable errors in revenue on the projected exported energy in the transmission system, while avoiding the provision of distorted incentives for sale through T-W or through Day Ahead and/or Intra-Day Market.

7.14 There will be no adjustment of factor K in favor of the regulated producer to the extent that the difference between the projected and actual total production on the wholesale market or the T-W or non T-W sales volume was a result of market manipulation.

7.15 CERA will reward each regulated producer for each positive return in relation to the compensations of the controllable operating costs related to the regulated generation activity and covered by T-W, in accordance with the provisions of Annex 3 to this Decision.

T-NH: Use of Transmission System Tariff

7.16 T-NH is the use tariff of the transmission system and will apply to all loads of the electricity network of Cyprus. T-NH will be defined in such a way that it is possible to recover the allowed total revenue of the Transmission System Owner, not including connection revenue, other customer contributions, and the costs associated with the Transmission System Operator of Cyprus (TSOC).

7.17 T-NH shall be applied to each Load Representative that absorbs energy from the Transmission System or the Distribution System, taking into account the losses of the Distribution System (for metres connected to Distribution), depending on the voltage level of the metre represented. In the case of a Load Representative acting as a Supplier, the Supplier shall impose the same charge on its customers.

7.18 T-NH shall be applied on a single geographical basis throughout Cyprus.

7.19 The recovery of the allowed total revenue of the Transmission System Owner is derived by Z_1% from power charges (in €/MW) and by 100-Z_1% from energy charges (in €/MWh). Value $Z_{1\%}$ is set by CERA in such a way as to achieve a cost-oriented definition of unit power and energy charges included in the formula for calculating the system use charge for each Load Representative (for each HV, MV, LV customer it represents). The allocation of the total allowed revenue of the Transmission System Owner into power part ($EE_{ΣΜ,ΣΙ}$) and energy part ($EE_{ΣΜ,ΣΕ}$) is based on the following principles:

- The power charge mainly reflects the capital expenditure (CAPEX) relating to the investments and assets of the transmission system (depreciation of fixed assets, return of frozen funds in fixed assets, etc.).
- The energy charge reflects the other operating costs of the transmission system (OPEX) (maintenance and operation costs of the network, etc.).

The amount of the above percentage Z_1% will be periodically reassessed every M1 years by CERA, based on a relevant recommendation of CERA, which will include:

- Estimate of changes in the form of the customer load curve (and consequently of the transmission system), due to structural changes in the characteristics of electricity consumption and production (e.g. energy savings, increased in scattered production and self-production from RES, dissemination of electricity storage, penetration of electrification, etc.)
- Estimate of the impact of these changes on the cost of the transmission system and anticipation of the future evolution of the total allowed revenue of the Transmission System Owner and its individual components (CAPEX, OPEX).
- Quantitative assessment of the charges that occur per user category, based on historical data and their projection in the future, taking into account the above changes, in order to properly configure the methodologies for calculating the revenue and allocation of charges to the user categories.

On the basis of the above recommendation and the evolution of the energy system in general, and in particular the own consumption and the consequent transfer of a part of the costs to consumers who do not have on-site production or energy storage, CERA may periodically adjust the above percentage Z1% and/or to introduce, at a later time, a third fixed charge part, which will be imposed on the basis of the number of respective consumers (in €/consumer) or on the basis of the agreed power of the respective consumers (in €/MW).

When determining the value Z1%, CERA shall take into account the impact on the charges of end-users, on the basis of a documented recommendation of TSOC. In order to mitigate any sudden variations in the charges in relation to the existing system, CERA may plan a gradual transition to the new charging system with an increased power component, with appropriate time scaling and gradual application of the individual provisions, where necessary.

The amount of the above rate Z_1% is set out in Annex 4 to this Decision.

7.20 The unit charge of the T-NH energy part (€/MWh) shall be determined by dividing the allowed revenue recovered by energy charges within one year ($EE_{ΣΜ,ΣΕ}$) to the sum of the projected energy load of all the customers of the Transmission System and the Distribution System in that year. The energy load of a customer shall correspond to the energy load of the customer as measured at the customer's location, adjusted to the average annual losses of the Network at the voltage level to which the user is connected and the average annual losses of the Network at all voltage levels above that level.

7.21 The unit charge of the T-NH power part (€/MW) shall be determined through a **six-step** approach, as described below:

7.22 **Step 1:** Determination of high load hours of the transmission system

The determination of the high load hours of the transmission system shall be based on a study to be prepared by the TSOC and updated before the beginning of each year. The study takes into account available data from historical load curves, sufficient time horizon (3-5 years) and projected changes of their form, based on the documented judgment of the TSOC as appropriate. On the basis of this study, specific "high load time zones" shall be identified, which are the 24-hour time zones in which the highest loads of the system appear and may vary depending on the period of the year. The "high load time zones" may be determined for periods of the year with different durations, which, however, can not exceed the specified billing period (e.g. for monthly invoicing, the "high load time zones" may not cover periods of more than one month). In their entirety, "high load time zones" should cover an adequate portion of the year, so as to avoid the determination of charges based on individual hours, days or months of the year. For each "high load time zone" this probability will be determined to include a charge close to the peak of the system. The sum of the probabilities attributed for the whole year will be 1 (e.g. a) "High load time zones" 1-5 (one zone per month), with a probability of 10% per month: November-March, working days, 11:00-14:00, b) "High load time zones" 6-8 (one zone per month), with a probability of 5% per month: December-February, working days, 19:00-21:00, c) "High load time zones" 9-16 (one zone per month), with a probability of 5% per month: April-October, all days, 19:00-22:00).

7.23 **Step 2:** Allocation of the allowed revenue for the power part ($EE_{ΣΜ,ΣΙ}$) between consumers of the Transmission System (HV) and the Distribution System (MV and LV), based on their total share at the peak of the Transmission System.

The expected contribution of all HV consumers in the loading of the transmission system can be determined by the sum of the historical load curves of all HV consumers, with an appropriate adjustment to take into account projected changes in the following year. The calculation of historical load curves shall be made based on the available time series of measurement data for past years on a sufficient time horizon (3-5 years). Respectively, the contribution of consumers of the Distribution System (as a whole) in the loading of the transmission system shall be based on the sum of the available time series of all HV substations, which feed consumers of the Distribution System (MV or LV) and appropriate adjustment to receive them, taking into account their projected future development in the following year. The projected maximum synchronized power of LV consumers ($P_{ΥΤ\text{-}αιχμή,i}$) and consumers of the Distribution System ($P_{ΥΤ\text{-}αιχμή,i}$) in the predetermined "high load time zones" (i) is determined based on the resulting time series.

The allocation power of these two categories of consumers results from the weighting of this maximum power within each "high load time zone" with the probability corresponding to the zone (p_i):

$$\text{HV: } P_{\varepsilon\pi\iota\mu-YT} = \sum_i \left(P_{\alpha\iota\chi\mu ή-YT,i} * p_i\right)$$

$$\text{DN: } P_{\varepsilon\pi\iota\mu-\Delta\Delta} = \sum_i \left(P_{\alpha\iota\chi\mu ή-\Delta\Delta,i} * p_i\right)$$

The allowed revenue is finally divided into these two main categories of consumers using the following formulas:

$$\text{Transmission System: } EE_{\Sigma M,\Sigma I,YT} = EE_{\Sigma M,\Sigma I} * \left(\frac{P_{\varepsilon\pi\iota\mu-YT}}{P_{\varepsilon\pi\iota\mu-YT} + P_{\varepsilon\pi\iota\mu-\Delta\Delta}}\right)$$

$$\text{Distribution System: } EE_{\Sigma M,\Sigma I,\Delta\Delta} = EE_{\Sigma M,\Sigma I} * \left(\frac{P_{\varepsilon\pi\iota\mu.-\Delta\Delta}}{P_{\varepsilon\pi\iota\mu-YT} + P_{\varepsilon\pi\iota\mu-\Delta\Delta}}\right)$$

7.24 **Step 3:** Identification of unit charges for HV consumers

The allowed revenue, corresponding to each "high-load time zone", are obtained by multiplying the total allowed annual revenues, recovered through power charges from consumers of the transmission system ($EE_{\Sigma M,\Sigma I,YT}$), with the probability corresponding to the corresponding zone (p_i).

For each "high load time zone", the individual contribution of each consumer HV (λ) to the peak charge of the transmission system is determined based on the maximum demand that each consumer is expected to have within the respective zone ($P_{\alpha\iota\chi\mu ή\text{-}YT,\lambda,i}$) in the following year.

The unit charge of the power part, recovered by consumers of the transmission system, is determined for each "high load time zone"[1] by dividing the allowed revenue of the respective zone by the sum of the estimated individual contribution in the peak charge of the transmission system:

$$MX_{\Sigma M,\Sigma I,YT,i}(€/MW) = EE_{\Sigma M,\Sigma I,YT} * \frac{p_i}{\sum_\lambda P_{\alpha\iota\chi\mu ή-YT,\lambda,i}}$$

The final charging power of each consumer of the transmission system for each "high load time zone" shall be calculated on the basis of the customer's peak load during these hours, as measured at the customer's location.

7.25 **Step 4:** Allocation of the allowed revenue recovered by consumers of the Distribution System into categories of consumers

The allocation of transmission system costs to consumers of the Distribution System is determined based on their contribution in charging the transmission system. To the extent that no measurement data is available for all consumers of the Distribution System, this can be done through consumer load curves, i.e. by grouping consumers into categories that may relate to grouping by voltage level (MV and HV) and/or and by

[1] For the purpose of simplifying the charging system, unit charges may be calculated on a single basis for groups of "high load time zones" with similar probability, so as to obtain a single unit charge for all such zones: $MX_{\Sigma M,\Sigma I,YT,\Sigma i}(€/MW) = EE_{\Sigma M,\Sigma I,YT} * \frac{\sum_i p_i}{\sum_i \sum_\lambda P_{\alpha\iota\chi\mu ή-YT,\lambda,i}}$

type of consumer and will be determined after a relevant load study of the DSO, which will be updated before the beginning of each regulatory review period.[2]

The expected contribution of each category (k) to the peak of the system and, through it, the sharing power of each category ($P_{al\text{-}k}$) is determined based on the load curve per category of consumers, for each "high load time zone". The allowed revenue is shared by all consumers of the Distribution System in the individual categories, based on the following formula:

$$EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa} = EE_{\Sigma M,\Sigma I,\Delta\Delta} * \frac{P_{\varepsilon\pi\iota\mu-\kappa}}{\sum_{\kappa} P_{\varepsilon\pi\iota\mu-\kappa}}$$

Since the available measurement data are not sufficient to determine appropriate load curves per consumer category, the allowed revenue shall be divided into the individual categories based on the total energy expected to be consumed by each consumer category in the following year:

$$EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa} = EE_{\Sigma M,\Sigma I,\Delta\Delta} * \frac{E_{\kappa}}{\sum_{\kappa} E_{\kappa}}$$

7.26 **Step 5:** Allocation of the allowed revenue of each category into a part to be recovered by consumers by telemetry and a part to be recovered by consumers without telemetry

The allocation of the cost of the transmission system (allowed revenue) to the individual consumers of the Distribution System shall be determined based on the behavior of the consumers and their contribution in the charging of the Transmission System. Until a time series of measurement of the absorbed power of all consumers of the Distribution System is available, it is necessary to apply distinct allocation methodologies for consumers with telemetry and consumers without telemetry. To this end, the DSO shall publish annually detailed statistics on the number and type (annual energy consumption, agreed power, etc.) of consumers of each category having a telemetry, in relation to all consumers in the category, and the corresponding figures for the following year.

If, at the discretion of CERA and following a documented suggestion by the DSO, the percentage of consumers in a category expected to have a telemetry within the next year is considered sufficient for the representative allocation of costs, then the total allowed revenue of each category of consumers ($EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa}$) is initially allocated to the part recovered by consumers of the category with telemetry ($EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\mu\tau}$) and to the part recovered by consumers of the category without telemetry ($EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\chi\tau}$), based on the total energy expected to be consumed by each subgroup of consumers of the category in the following year:

With telemetry: $EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\mu\tau} = EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa} * \frac{E_{\kappa,\mu\tau}}{E_{\kappa,\mu\tau} + E_{\kappa,\chi\tau}}$

Without telemetry: $EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\chi\tau} = EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa} * \frac{E_{\kappa,\chi\tau}}{E_{\kappa,\mu\tau} + E_{\kappa,\chi\tau}}$

Otherwise, if the percentage of consumers in a category expected to have a telemetry is not considered sufficient for the representative cost allocation, then step 5 is omitted

[2] The study should take into account the data available for each consumer type, the data available from individual consumer measurements, as well as projected changes in their load curve. The study will also determine the load curve of each category, which will be used to calculate the contribution of each category at the peak of the system. The load curve of each category therefore concerns the synchronized curve of all consumers in each category, which is different from the load curve for a typical single customer within a customer category.

and the cost allocation to individual consumers takes place for all consumers, based on their agreed power in accordance with the provisions of paragraph 7.27 for consumers without telemetry.

7.27 **Step 6:** Identification of unit charges for individual consumers of each category

The final cost allocation to individual consumers of each category is determined according to the following methodology:

- Consumers with telemetry
  The unit charge ($MX_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\mu\tau,i}$) for each "high load time zone" shall be determined on the basis of the individual contribution in the peak charge of the transmission system, according to the methodology described in paragraph 7.25:

$$MX_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\mu\tau,i}(€/MW) = EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\mu\tau} * \frac{p_i}{\sum_\lambda P_{\alpha\iota\chi\mu\acute{\eta}-\mu\tau,\lambda,i}}$$

  The final charging power of each consumer with telemetry shall be calculated on the basis of the customer's peak load in each "high load time zone", as measured at the customer's site. For customer categories, which include both MV and LV consumers and in order to compare the size of the measured power, the measured power of the LV consumers is adjusted based on the average annual losses of the LV network.

- Consumers without telemetry
  The allowed revenue is allocated to individual consumers without telemetry[3] based on the agreed power:

$$MX_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\chi\tau}\,(€/MW) = \frac{EE_{\Sigma M,\Sigma I,\Delta\Delta,\kappa,\chi\tau}}{\sum_\lambda P_{\sigma\upsilon\mu\varphi-\chi\tau,\lambda}}$$

  The final charging power of each consumer without telemetry will correspond to the agreed power of the customer. For customer categories, which include both MV and LV consumers and in order to compare the size of the measured power, the measured power of the LV consumers is adjusted based on the average annual losses of the LV network.

7.28 CERA will reward the Owner of the Transmission System for each positive return in relation to the compensations of the controllable operating costs related to the regulated transmission activity and covered by T-NH, in accordance with the provisions of Annex 3 to this Regulatory Decision.

T-NM: Use tariff of the Medium Voltage Distribution System

7.29 T-NM is the tariff for the use of the Distribution System at medium voltage and will apply to all loads connected to the Cyprus Electricity Distribution System. T-NM will be defined in such a way as to allow the recovery of the allowed total revenues of the distribution network at the level of the medium voltage, with the exception of connection revenue and other customer contributions.

7.30 T-NM will be applied to each Load Representative that absorbs energy from the Distribution System, taking into account the losses of the Distribution System, depending on the voltage level where the represented metre is located. In the case of

[3] The same methodology may apply to all consumers in a category, provided that the proportion of consumers in a category with telemetry is not considered sufficient and representative for the whole category.

a Load Representative acting as a Supplier, the Supplier shall impose the same charge on its customers.

7.31 T-NM shall be applied on a single geographical basis throughout Cyprus.

7.32 The recovery of the allowed total revenue of the Owner of the Distribution System at medium voltage is derived by Z_2% from power charges (in €/MW) and by 100-Z_2% from energy charges (in €/MWh). The value of Z_2% is defined and periodically reassessed every 2 years by CERA taking into account the criteria set out in paragraph 7.19. The amount of the above rate Z_2% is set out in Annex 4 to this Regulatory Decision.

7.33 The unit charge of the T-NM energy part (€/MWh) shall be determined by dividing the allowed revenue recovered by energy charges within one year to the sum of the projected energy load of all the consumers connected at the MV and LV levels of the Distribution System. The energy load of a customer will correspond to the energy load of the customer as measured at the customer's site, adjusted to the average annual losses of the Distribution System. For customers connected at the LV level of the Distribution System, the loss adjustment will be related to the average losses in the entire LV and MV Distribution System. For customers connected to the MV level of the Distribution System, the loss adjustment will be related to the average losses at the MV level only.

7.34 The charge of the consumers of the Distribution System with respect to the T-NM power part shall be determined in principle by their measured maximum monthly demand, irrespective of the time period that appears within the month, or by their agreed power, in the absence of a measurement of power, in accordance with the following:

If at the discretion of CERA and after a documented suggestion of the DSO, the percentage of consumers of the Distribution System that are expected to have a measurement of the maximum monthly demand within the next year, is considered sufficient for the representative cost sharing, then the total allowed revenue shall be allocated initially to the part recovered by consumers by measuring the maximum monthly demand ($EE_{MT,\, mi}$) and to the part recovered by consumers without measuring the maximum monthly demand ($EE_{MT,χι}$), based on the total energy expected to be consumed by each consumer subgroup in the following year. Based on this allocation, the unit charges (€/MW) of the T-NM power part are determined according to the following formulas:

- Consumers with a maximum monthly power measurement:
  - $EE_{MT,\mu\iota} = EE_{MT} * E_{\Delta\Delta,\mu\iota}/(E_{\Delta\Delta,\mu\iota} + E_{\Delta\Delta,\chi\iota})$
  - $MX_{MT,\mu\iota}(€/MW) = EE_{MT,\mu\iota}/\sum_{\lambda 1} P_{\alpha\iota\chi\mu ή-\mu\iota,\lambda}$
- Consumers without a maximum monthly power measurement:
  - $EE_{MT,\chi\iota} = EE_{MT} * E_{\Delta\Delta,\chi\iota}/(E_{\Delta\Delta,\mu\iota} + E_{\Delta\Delta,\chi\iota})$
  - $MX_{MT,\chi\iota}(€/MW) = EE_{MT,\chi\iota} / \sum_{\lambda 2} P_{\sigma\upsilon\mu\varphi-\chi\iota,\lambda}$

where:

- EU_{MT}, the allowed revenue corresponding to the T-NM tariff
- $EE_{MT,μι}$, the part of the allowed revenue recovered by consumers of the Distribution System with a maximum monthly power measurement
- $EE_{MT,χι}$, the part of the allowed revenue recovered by consumers of the Distribution System without a maximum monthly power measurement

- $E_{\Delta\Delta,\mu\iota}$, the projected annual energy consumption by all consumers of the Distribution System with a maximum monthly power measurement
- $E_{\Delta\Delta,\chi\iota}$, the projected annual energy consumption by all consumers of the Distribution System without a maximum monthly power measurement
- $MX_{MT,\mu\iota}$, the unit charge for consumers of the Distribution System with a maximum monthly power measurement
- $MX_{MT,\chi\iota}$, the unit charge for consumers of the Distribution System without a maximum monthly power measurement
- $P_{\alpha\iota\chi\mu\acute{\eta}\text{-}\mu\iota,\lambda}$ the average of the monthly peak loads of any time, which are expected by each individual consumer (λ) of the distribution network with a maximum monthly power measurement in the following year
- $P_{\sigma\upsilon\mu\varphi\text{-}\chi\iota,\lambda}$, the agreed power of each individual consumer (λ) of the Distribution System without maximum monthly power measurement
- λ_1, the number of consumers of the distribution network, expected to have a maximum monthly power measurement in the following year; and
- λ_2, the number of consumers in the Distribution System, who are not expected to have a maximum monthly power measurement in the following year;

Otherwise, if the percentage of consumers in a category expected to have a maximum monthly power measurement is not considered sufficient for the representative cost allocation, then the cost allocation to individual consumers takes place for all consumers, based on their agreed power in accordance with the provisions above for consumers without a maximum monthly power measurement.

7.35 The final charging power of each consumer shall be calculated on the basis of the measured or agreed power, as set out above, adjusted to the average annual losses of the distribution network, according to the methodology described in paragraph 7.33.

7.36 In order to increase the proportionality of the power charges, and since the charges for the use of the Distribution System are applied on a uniform geographical basis throughout Cyprus, it may be considered whether and to what extent the behavior of consumers presents some degree of uniformity throughout the network distribution and induces high loads simultaneously, or almost simultaneously in all individual distribution networks. To this end, the DSO, before the start of each regulatory period, shall prepare a study based on the load flows in the individual distribution networks, in order to draw the necessary useful conclusions as regards the degree of uniformity of the load of the distribution network.

If this study reveals significant uniformity in the loading of the Distribution System in its entirety (at the discretion of CERA and upon suggestion of the DSO), this loading must match the loading of the transmission system, and therefore the charging power (revenue sharing) of consumers should be determined based on the contribution of consumers in the peak loading hours of the network. These hours shall, in this case, match the possible hours of peak demand for the “high load time zones” determined for the transmission system, based on the provisions of paragraph 7.22. Therefore, for the determination of the unit charges (€/MW) of the T-NM power part, the same methodology shall be followed, as described in paragraphs 7.21 - 7.27 for the T-NH power part.

7.37 CERA will reward the Owner of the Distribution System for each positive return in relation to the compensations of the controllable operating costs related to the regulated distribution activity at the medium voltage level and covered by T-NM, in accordance with the provisions of Annex 3 to this Regulatory Decision.

T-NL: Use tariff of the Low Voltage Distribution System

7.38 T-NL is the tariff for the use of the Distribution System at low voltage and will apply to all loads connected to the low voltage level of the Cyprus Electricity Distribution System. T-NL will be defined in such a way as to allow the recovery of the allowed total revenues of the distribution network at the level of the low voltage, with the exception of connection revenue and other customer contributions.

7.39 T-NM shall apply to each Load Representative that absorbs energy from the Low Voltage Distribution Network, taking into account the losses corresponding to the Low Voltage Distribution Network. In the case of a Load Representative acting as a Supplier, the Supplier shall impose the same charge on its customers.

7.40 T-NL shall be applied on a single geographical basis throughout Cyprus.

The recovery of the allowed total revenue of the Owner of the Distribution System at low voltage is derived by Z_3% from power charges (in €/MW) and by 100-Z_3% from energy charges (in €/MWh). The value of Z_3% is defined and periodically reassessed every 3 years by CERA taking into account the criteria set out in paragraph 7.19. The amount of the above rate Z_3% is set out in Annex 4 to this Decision.

7.41 The unit charge of the T-NL energy part (€/MWh) shall be determined by dividing the allowed revenue recovered by energy charges within one year to the sum of the projected energy load of all the consumers connected at the LV level of the Distribution System. The energy load of a customer will correspond to the energy load of the customer as measured at the customer's site.

7.42 The charge of the consumers of the Distribution System with respect to the T-NL power part shall be determined in principle by their measured maximum monthly demand, irrespective of the time period that appears within the month, or by their agreed power, in the absence of a measurement of power. If at the discretion of CERA and after a documented suggestion of the DSO, the percentage of LV consumers that are expected to have a measurement of the maximum monthly demand within the next year, is considered sufficient for the representative cost sharing, then the total allowed revenue shall be allocated initially to the part recovered by consumers by measuring the maximum monthly demand ($EE_{XT,μι}$) and to the part recovered by consumers without measuring the maximum monthly demand ($EE_{XT,χι}$), based on the total energy expected to be consumed by each consumer subgroup in the following year. Based on this allocation, the unit charges (€/MW) of the T-NM power part are determined according to the following formulas:

- Consumers with a maximum monthly power measurement:
  - $EE_{\mathrm{XT},\mu\iota} = EE_{\mathrm{XT}} * E_{\mathrm{XT},\mu\iota}/(E_{\mathrm{XT},\mu\iota} + E_{\mathrm{XT},\chi\iota})$
  - $MX_{\mathrm{XT},\mu\iota}(€/MW) = EE_{\mathrm{XT},\mu\iota}/\sum_{\lambda 1} P_{\alpha\iota\chi\mu ή-\mu\iota,\lambda}$
- Consumers without a maximum monthly power measurement:
  - $EE_{\mathrm{XT},\chi\iota} = EE_{\mathrm{XT}} * E_{\mathrm{XT},\chi\iota}/(E_{\mathrm{XT},\mu\iota} + E_{\mathrm{XT},\chi\iota})$
  - $MX_{\mathrm{XT},\chi\iota}(€/MW) = EE_{\mathrm{XT},\chi\iota} / \sum_{\lambda 2} P_{\sigma\upsilon\mu\varphi-\chi\iota,\lambda}$

Otherwise, if the percentage of consumers in a category expected to have a maximum monthly power measurement is not considered sufficient for the representative cost allocation, then the cost allocation to individual consumers takes place for all consumers, based on their agreed power in accordance with the provisions above for consumers without a maximum monthly power measurement.

7.43 The final charging power of each consumer shall be calculated on the basis of the measured or agreed power, in accordance with the above.

7.44 CERA will reward the Owner of the Distribution System for each positive return in relation to the compensations of the controllable operating costs related to the regulated distribution activity at the low voltage level and covered by T-NL, in accordance with the provisions of Annex 3 to this Regulatory Decision.

T-AS: Tariff for the provision of Ancillary Services

7.45 The TSOC shall be responsible for ensuring the ancillary services necessary to maintain the balance of the system, the quality of electricity and the restoration of the system after an extensive interruption or other abnormal situations. In addition, the TSOC may provide long-term reserves to ensure that the system has sufficient capacity and/or flexibility. The long-term reserve of the System will be secured by the application of any mechanism (or competitive procedure) of compensation for long-term availability of power and/or flexible power and/or contingency power and/or power of strategic reserves that may be required by the Transmission System Operator of Cyprus of the Electricity System of Cyprus. Specifically, the above services include:

a. the long-term reserve;

b. the frequency containment and restoration reserve;

c. the replacement reserve;

d. the synchronization and supply of energy and reserves from Contracted production units;

e. black start after total shutdown;

f. voltage regulation;

g. other ancillary services which may be required by the TSOC for the proper and safe operation of the system.

The procurement of the ancillary services and the long-term reserve under the above points (a)-(e) is done through daily, monthly or annual tender procedures or through contracts with the providers of these services. The recovery of the necessary revenue for the payment of these services to the providers is described in the Trading and Settlement Rules.

The T-AS shall be set in such a way as to allow the TSOC to recover the authorized costs of ancillary services only under the above points (f) and (g) which are not included in the wholesale electricity market procedures and are not described in the Trading and Settlement Rules.

7.46 The T-AS shall apply to all suppliers (regulated and non-regulated). A supplier that does not hold a dominant position will be free to decide what is the best way to recover costs from its customers, according to paragraphs 3.2 and 6.13.

7.47 As regards suppliers holding a dominant position, the T-AS shall include the cost of the above ancillary services under points (f) and (g) attributable to the supplier with a dominant position.

Voltage regulation

7.48 Voltages in the networks are controlled by adjustments to the inactive power of the generators and to the steps of the transformers and by using capacitors and inductors in the transmission and distribution systems. A certain level of voltage regulation services is provided by all producers according to the network code. The TSOC may provide additional voltage regulation services by means of contracts and provide voltage regulation services to the transmission system.

7.49 The T-AS tariff element used to recover the allowed cost of voltage regulation services shall be recovered through a charge imposed on suppliers in the same way that T-NH is imposed on all customers connected to the electrical system.

7.50 In order to avoid doubts, to the extent that fixed transmission data are used to provide voltage regulation services, the capital and operating costs associated with such fixed assets will be recovered through the T-AS.

Frequency control

7.51 The system should be able to continuously monitor and control the frequency as a result of discrepancies between production and demand of the system.

7.52 The T-AS tariff element used to recover the allowed costs of the TSOC that ensures the ancillary service of frequency control shall be imposed as described in the Detailed Design for differentiation of the regulatory framework for the operation of the electricity market in Cyprus, Regulatory Administrative Act No 164/2015, and as set out the Trading and Settlement Rules.

T-BM: Tariff for Commercial and Accounting Management Services

7.53 The commercial and accounting management services are related to the costs incurred by a supplier for the management of its customers, e.g. contract and pricing management, provision of telephone service and complaints service, provision of retail stores, etc.

7.54 A supplier that does not hold a dominant position will be free to decide what is the best way to recover the cost of commercial and accounting management services from its customers, according to paragraphs 3.2 and 6.13.

7.55 In the case of a dominant supplier, the tariff applied to customers to recover the costs of commercial services shall be regulated in the form of a limit for reasonable commercial and accounting management expenses plus an allowed mark-up on those costs.

7.56 The allowed mark-up shall be the one set out in Annex 4.

7.57 The regulated tariff for commercial and accounting management services shall be in the form of a fixed daily charge per customer, which may vary depending on the type and size of the customer and the type of metre, according to paragraphs 3.2 and 6.13.

7.58 Prior to the commencement of each year, the regulated supplier shall propose all the tariffs for the commercial and accounting management services applicable for that year. CERA shall examine the proposal and decide whether to approve or reject the proposed tariffs.

T-PSO: Tariff for the Public Service Obligations Fee

7.59 The T-PSO shall be imposed on consumers for their compliance with the Public Service Obligations. The TSOC shall be responsible for the collection of the PSO fee by the Load Representatives and its return to the competent Body.

7.60 The T-PSO shall be established in such a way as to allow the recovery of the allowed costs in relation to the activities described in paragraph 7.59.

7.61 The T-PSO will be recovered through a charge that will be imposed on consumption and which will be determined by dividing the cost recovered within one year by the sum of the projected energy load for that year of all customers connected to the electricity system.

7.62 T-PSO shall be applied to each Load Representative that absorbs energy from the Transmission System or the Distribution System, taking into account the losses of the Distribution System (for metres connected to Distribution), depending on the voltage level of the metre represented. In the case of a Load Representative acting as a Supplier, the Supplier shall impose the same charge on its customers.

7.63 For the purposes of this paragraph 7.61, the energy load of a customer shall correspond to the energy load of the customer as measured or estimated at the customer's location, adjusted to the average annual losses of the Network at the voltage level to which the user is connected and the average annual losses of the Network at all voltage levels above that level.

7.64 In the case of a user with on-site production, the T-PSO shall be applied as set out in the relevant decisions of CERA.

T-TSO: Tariff for the costs of the TSOC

7.65 The TSOC shall bear the costs of managing the electricity transmission system in Cyprus and the operating costs of the electricity market. The allowed cost of the TSOC shall be recovered through the T-TSO. The allowed cost includes the reasonable costs of the TSOC to carry out its operations including the cost of recording the measurements of all customers and producers connected to the Transmission System and informing the Load Representatives about the consumption measurements they represent.

7.66 T-TSO shall be applied to each Load Representative that absorbs energy from the Transmission System or the Distribution System, taking into account the losses of the Distribution System (for metres connected to Distribution), depending on the voltage level of the metre represented. In the case of a Load Representative acting as a Supplier, the Supplier shall impose the same charge on its customers.

T-MET: Tariff for Meter reading costs

7.67 The Distribution System Operator shall be responsible for the metre readings of the customer's deductions from the distribution networks, the energy generated in the distribution network and the processing of the meter readings to calculate the total energy of the electricity market participants in the distribution network. The distribution system owner is responsible for the purchase, installation and maintenance of metres in the distribution network.

7.68 T-MET shall cover exclusively the allowed revenue related to the cost of recording the metre readings of all customers and producers connected to the Distribution System and informing the Load Representatives about the metering data of the consumption they represent. For the avoidance of doubt, the allowed revenue related to the capital cost of the metres in the distribution network are covered by the T-NM and T-NL tariffs, the allowed revenue related to the costs of the metering readings in the transmission network are covered by the T-TSO and the allowed revenue related to the capital cost of metres in the transmission network are covered by the T-NH tariff.

7.69 In order to implement a simple and fair way of recovering the cost of recording the metre readings of all customers and producers connected to the Distribution System and of informing the Load Representatives about the metering data of the consumption they represent, the T-MET shall be imposed in the form of a fixed charge per metre to the Load Representatives. This charge shall be the same for all Distribution System Users, regardless of the type of metre installed and the voltage level of the connection.

7.70 A regulated supplier will pass on the costs associated with the T-MET to the customer in the same form and at the same level as the T-MET imposed on the supplier in relation to that customer.

7.71 Before the start of one year, the Distribution System Operator (DSO) shall propose the T-MET that shall apply for that year. CERA shall examine and approve or reject the proposal.

7.72 CERA shall reward the Distribution System Operator (DSO) for each positive return in relation to the compensations of the controllable operating costs related to the metre reading costs of all customers and producers connected to the Distribution System and covered by the T-MET, in accordance with the provisions of Annex 3 to this Decision.

T-RET: Supply tariffs and electricity market charges to the end consumer

7.73 T-RET is the regulated tariff applied to customers to recover the cost of supply from a supplier with a dominant position, including the costs associated with T-BM. A supplier that does not hold a dominant position will be free to set retail prices in accordance with paragraphs 3.2, 6.11 and 6.13. A supplier with a dominant position shall be initially permitted to purchase electricity generated from conventional production units through Bilateral Contracts only from regulated producers. The possibility of purchasing electricity from a regulated supplier, produced by non-regulated producers, through Bilateral Contracts may be authorized by a future decision of CERA. In order to avoid doubts, the above provision excludes the purchase of electricity generated by RES stations which, based on Regulatory Administrative Act No 164/2015 on the detailed design of the electricity market, Regulatory Decision No 01/2015, are represented on the wholesale market by the regulated supplier. The possibility of selling electricity through Bilateral Contracts from a regulated supplier on the wholesale market is not allowed and may be authorized by a future decision of CERA.

7.74 T-RET for a customer will include the sum:

a. of the cost of electricity supplied through the Wholesale Electricity Market and/or through the Deviations Clearing Mechanism;

b. of the details of all regulated tariffs as detailed in Table 1, imposed on the supplier holding a dominant position;

c. of the costs arising from the various accounts of the Market Operator, other than the costs resulting from the Deviations Clearing Accounts (Deviation Energy Account and Deviation Energy Surcharge Account) which is included under (a)

d. of the net cost incurred by the regulated supply company and derived from transactions carried out in the Electricity Market. These transactions include, for example, the purchase of energy from RES stations that are included in National Sponsorship Schemes, the purchase of Guarantees of Origin, etc. With regard to the cost of purchasing energy from RES stations that are included in the National Sponsorship Schemes, the relevant cost taken into account for the setting of the final T-RET value should be revised per year to the change in the unit base energy purchase price (in €/kWh) from RES-e, as it is established on the basis of the CERA-approved methodology for the calculation of fuel adjustment of basic tariffs and energy purchase price from RES-e. There will also be an ex-post revaluation of the net cost borne by the regulated supply company and derived from transactions carried out within the Electricity Market by applying the revaluation to the T-RET for the year Y+2.

7.75 The above value of T-RET shall not include charges incurred by the regulated supply activity and derived from the Non-Compliance Charges Account, as a result of the participation of the regulated supply activity in the Wholesale Electricity Market and the Real Time Balancing Market, based on the applicable provisions of the Electricity Market Rules.

7.76 The sum of the above cost items (a), (c) and (d) constitutes the “Competitive cost tariff of a regulated supply activity for the supply of electricity to customers” (T-CS in Table 1) and will be included in the total unit price of the electricity charge (in €/kWh) in the customer invoice.

T-ILU: Charge Tariff for the use of the interconnection line

7.77 T-ILU is imposed on the users of the Cyprus-Crete interconnection line (producers) (PCI 3.10.2) as provided for in the RAE-CERA Agreement on the Cross-Border Cost Sharing of the Joint Project No 3.10.2 Interconnection Between Kofinou (CY) and Korakia, Crete (EL) dated 10 October 2017.

7.78 With regard to PCI 3.10.2 in the case of Cyprus, and according to the cost-benefit analysis submitted by the Implementing Body and prepared on the basis of the ENTSO-E Methodology, the positive benefits for producers and consequently the increase of invoices to cover revenues from the requirements of PCI 3.10.2 shall be borne solely by the producers. The details of the charge are set out in the RAE-CERA Agreement on the Cross-Border Cost Sharing for PCI 3.10.2 dated 10 October 2017.

Annex 1: Principles of Regulated Asset Base (RAB)

1. Introduction

1.1 Regulated Asset Base (RAB)

"RAB" means the Regulated Asset Base, i.e. the net book value of the regulated assets of an organization used exclusively for the provision of regulated services. The data included in the RAB must be used exclusively for the provision of regulated services. As a general rule, only those profitable investments that are in the long-term interest of the customer and approved by CERA should be included in the regulated company's RAB.

The RAB must be calculated on an annual basis (the calculation will be made at the beginning of the regulatory review period separately for each year of the period) for each of the regulated activities of Transfer, Distribution and Production, if the latter is a regulated activity of a producer with a dominant position. The RAB is used for the determination of the Depreciation of Fixed Assets as well as for the Return on Capital, i.e. the Return of the RAB.

2. Calculation and Parameters of the RAB

2.1 RAB equation

The RAB is calculated as follows, at the end of each year:

$$\mathbf{RAVB_T = RAVB_{T-1} + INV_T - S_T - D_T - \Delta CC_T + \Delta WC_T}$$

Where:

t = reference year

$RAVB_t$ = Total adjustable RAB of the reference year, i.e. final RAB.

$RAVB_{T-1}$ = Approved RAB of the previous year, i.e. initial RAB.

INV_t = Investments (capital expenditure) of the reference year. It concerns completed projects and the equipment is put into commercial operation. Work in progress is not included.

S_t = Net book value of sales/assignments in the reference year. **D_T** = Depreciation in the reference year.

ΔCC_T = Change in the net book value in the Customer Contributions during the reference year.

ΔWC_T = Change in the Working Capital during the reference year.

Each electricity activity must maintain a RAB for each of the regulated activities of Transport, Distribution and Production if the latter is a regulated activity of a producer holding a dominant position, in accordance with the principles set out below. The allocation of the fixed assets in each regulated activity carried out by the electricity activity shall be carried out in accordance with the Accounting Separation Regulations of the activities of the regulated activity. The separation criteria used for the allocation of fixed assets between the different activities are updated on an annual basis and are subject to audit by independent auditors, in accordance with the Regulatory Accounting Guidelines for the preparation of Separate Accounts (SA).

2.1.1 Average RAB

The best practice for calculating allowed revenue (AR) is to use the average RAB, i.e. the average of the initial and final RAB, as follows:

$$\textbf{AR RAVB}_T = (\textbf{RAVB}_T + \textbf{RAVB}_{T-1}) / 2$$

Where:

AR ARVV$_T$ = The RAB used to calculate the PRs.

2.2 Method of valuation of fixed assets

The method of valuation of fixed assets (e.g. acquisition costs, replacement costs, etc.) must be in accordance with the applicable Statement of Regulatory Practice and Methodology of Establishing Electricity Tariffs, as approved by CERA, and any other relevant decisions.

The method of valuation of fixed assets is defined as the historical cost (acquisition cost).

2.3 Useful Life of Fixed Assets and Depreciation Method

The useful life of fixed assets included in the RAB must be approved by CERA.
The Depreciation Method for the assets included in the RAB is the straight line method.

2.4 Working Capital

The Working Capital (WC) includes all current assets and liabilities of the activity, except for interest-bearing short-term deposits and liabilities. The WC of each regulated activity of Generation, Transport and Distribution is included in the RAB of that activity. Short-term capital contributions are deducted from short-term liabilities.

2.5 Work in progress

Work in progress must not be included in the RAB. Inclusion of Work in progress in the RAB violates the principle of “Use and Benefit” which is a fundamental principle of regulation (this principle requires that in order for customers to pay for any asset it must be fully used and provide a benefit to those customers). The RAB may not be burdened with investments in projects that have not yet been implemented and therefore have not been put into operation (thus, existing customers will not pay, through the tariffs, for investments from which they will benefit in the future or which may not benefit themselves, but new customers).

Each electricity activity must maintain and carry out a regular check of the Register of Work in progress and evaluate which fixed assets must be capitalized and transferred to the Register of Fixed Assets and which must remain in the Work in progress until their completion.

CERA may carry out regular audits of the Register of Work in progress in order to assess compliance of Work in progress with the respective approved investment program of the regulatory review period, as referred to in Annex 4.

2.6 Capital Contributions

The RAB shall not include the value of the fixed assets or the part of the value of the fixed assets financed by contributions from customers or producers.

Depreciation of Capital Contributions shall not be included in the calculation of the Network Use charges. Depreciation of capital contributions shall be deducted from the reasonable costs for determining the Allowed Revenue.

Capital Contributions must be directly linked to specific projects (and fixed assets), so that they are not required to be allocated to the Transmission and Distribution Activities at the end of the year. If in any case it is not possible to immediately allocate a capital contribution to specific projects, then the electricity company must provide CERA with the necessary justification for the methodology used in determining the separation factors.

2.7 Non-regulated activities

As regards the regulated activity, the RAB should not include fixed assets related to unregulated activities, such as:

- Desalination plant
- Maintenance of Road Lighting
- Design, Supply and Installation of Photovoltaic Systems for third parties
- EAC agreements with companies active in the telecommunications sector Other contracts
- Other non-regulated activities

The above activities are not an integral part and a necessary task of the three main regulated activities of the regulated activity (Production, Transmission and Distribution), and therefore may not be included in the RAB.

2.8 Investments (Capital expenditure)

CERA shall conduct an **ex-ante** assessment of the profitability of an activity's proposed investment plan for the forthcoming regulatory period, taking into account the future increase in demand, the composition of fixed assets and any other relevant information. Electricity companies must submit their forecasts on capital expenditure to CERA.

The ex-ante assessment will be carried out on the basis of the five-year business/investment plan to be submitted to CERA for approval and to be used for the determination of the Tariffs, in accordance with the applicable Statement of Regulatory Practice and Methodology of Establishing Electricity Tariffs, as approved by CERA, as well as any other relevant decisions.

CERA may carry out **ex post** assessments of the capital expenditure incurred. Their aim will be to identify the differences between the allowed capital expenditure in the *ex ante* audit and the actual investments made by the electricity company. In such cases, CERA shall investigate whether any excess amount is reasonable and the additional amount is likely to be exempted from the RAB. For the purpose of the ex post assessment, the documents referred to in paragraph 3.1 below shall be submitted.

3. Submission of documents and Audit procedure

3.1 Submission of documents to CERA

Electricity companies must submit to CERA, together with the Separate Accounts, the following items on an annual basis:

1. **Work in progress**
    - The Register of Work in progress, for each regulated activity separately and a comparison thereof with the approved five-year business/investment plan.
2. **RAB:**
    - The RAB for each regulated activity separately.
    - Any additions, assignments/transfers and the initial authorized RAB for each activity must be clearly presented.
    - The net book value of fixed assets of unregulated activities must be clearly presented.
    - Also, full reconciliation with the Separate Accounts must be presented.
3. **Investments (Capital expenditure):**
    - The Statement of Investments (Capital expenditure) that has been made during the year and a comparison with the plan for the regulatory review period (Annex 4) as approved by CERA (see Chapter 2.8 above).

3.2 CERA Audit Procedure

CERA (or its authorized consultants) may carry out audits to verify the correct implementation of the above by the electricity company.

For this purpose, apart from the aforementioned documents (see Section 3.1), CERA may access the accounts of electricity activities to provide additional interpretations or clarifications on the above.

Code Number of Fixed Asset	Activity (Production, Transmission, Distribution, Supply)	Description	Currency	Initial Balance of Cost	Additions	Divestments	Transmissions	Final Balance of Cost	Initial Depreciation Balance	Depreciation of the Year	Depreciation of Divestments	Depreciation of Transmission	Final Balance of Depreciation	Initial Residual Value Fixed assets	Final Residual Value of Fixed Assets
				€	€	€	€	€	€	€	€	€	€	€	€
Total Amount															

ANNEX A

Form for the submission of the Regulated Asset Base (RAB)

Code Number of Fixed Asset	Activity (Production, Transmission, Distribution, Supply)	Description	Currency	Initial Balance of Cost	Additions	Divestments	Transmissions	Final Balance of Cost	Initial Depreciation Balance	Depreciation of the Year	Depreciation of Divestments	Depreciation of Transmissions	Final Balance of Depreciation	Initial Residual Value of Fixed Assets	Final Residual Value of Fixed Assets
				€	€	€	€	€	€	€	€	€	€	€	€
Total Amount															

Annex 2: Methodology for the calculation of the Weighted Average Capital Cost (WACC) for the Production, Transmission and Distribution Activities

1. Introduction

The Weighted Average Capital Cost (WACC) is the minimum return that an activity or company is expected to pay on average to its shareholders/owners to finance its assets.

The WACC (before taxes) of an activity is the average weighted cost of the various sources of financing, with weighting factors of the percentage contributions of each source in the composition of the capital (i.e. the capital structure) of the activity at nominal prices and is defined as follows:

$$\mathbf{WACC\ (before\ taxes)} = \mathbf{R_e} \times \frac{\mathbf{E}}{\mathbf{(D+E)}} \times \frac{\mathbf{1}}{\mathbf{(1-T_c)}} + \mathbf{R}_{\boldsymbol{d}} \times \frac{\mathbf{D}}{\mathbf{(D+E)}}$$

Where:

$\mathbf{R_e}$ = Cost of Equity
$\mathbf{R_d}$ = Cost of Debts
E = Equity
D = Debts
$\mathbf{T_c}$ = Corporate Tax Rate.

The current Methodology refers to the Methodology for the calculation of the WACC for the regulated activities of Production (where the Producer is a dominant electricity company), Transmission and Distribution in the electricity market specifically for those regulated activities of a Vertically Integrated activity.

“Vertically Integrated activity” means an electricity activity or a group of electricity activities, where the same person or persons are entitled, directly or indirectly, to exercise control and where the activity or group of activities exercises at least one of the Transmission or Distribution activities and at least one of the Production or Supply activities (Article 2 of the Regulation on the Regulation of the Electricity Market of 2003-2012).

The assumptions and data used for the calculation of the WACC Methodology for each regulated activity shall be verified by CERA.

2. Methodology for calculating the WACC

2.1 R_e = Cost of equity

The calculation of the cost of equity results from the Capital Asset Pricing Model (CAPM). The CAPM can be calculated as follows.

$$R_e = r_f + \beta_e \times ERP$$

Where:

R_e: Cost of equity

r_f : Zero risk interest rate

r_m : Market risk

ERP = ($r_m - r_f$) : Risk of Equity

β_e: Systemic risk factor (“relevered beta” - “b”) - calculation of the systematic risk of a security

2.2 Risk-free interest rate (rf)

The risk-free interest rate is the expected return that an investment can bring to a fixed asset with zero risk. In practice, it is impossible to find an investment that is free from any risk. However, government-grade investment bonds that are freely traded on the market (from economically strong states) can be considered to have almost zero default risk, as these governments are unlikely to go bankrupt.

A bond-issuing government should be selected based on the low long-term risk, both for the government and for the bond, and the small changes in its performance over time. The bonds to be selected must be in the same currency as the one used by the activity, i.e. in this case the euro.

The expiry of the bond should reflect as best as possible the period of depreciation of the Company’s fixed assets. This period for EU enterprises operating in the electricity market is 20-25 years. However, long-term bonds are likely to be affected by exterior factors and therefore their nominal return may differ from the actual return.

Most countries in the EU use 10-year government bonds for the purpose of calculating the zero risk interest rate.

On the basis of the methodology described above, and taking into account the difficult economic conditions faced by Cyprus, the Zero Risk Interest Rate should not be calculated on the basis of the Cypriot government bonds, as the result would be a disproportionately high WACC.

Consequently, and until the severe economic conditions faced by Cyprus have passed, the government bonds of other EU countries which are considered low risk, for example Germany, should be used. Taking into account future inflation and any differences between their interest rates and their market performance, the return of these bonds until maturity is considered as the appropriate substitute for the Zero Risk Interest Rate.

The Zero Risk Interest rates do not differ between the Activities of a Vertically Integrated activity.

2.3 Risk of Equity

The Equity Risk is the additional return that an investor requires in order to accept the systematic risk arising from investments in fixed assets with a risk in excess of zero. It is essentially the excess return required due to the increased risk compared to a zero risk investment and is therefore calculated as the difference between the Market Risk (return) and the Zero Risk Interest Rate:

$$\mathbf{ERP = (r_m - r_f)}$$

Market Risk **(r_m)** is the additional return of a market portfolio compared to the zero interest risk rate. For the purposes of calculating the WACC, the market risk is defined as the historical average of the risks for a given market sample.

2.4 Systemic risk factor (“b” - beta)

“B” means the measurement of the systemic risk (non diversifiable risk) of a bond/share compared to the market as a whole and relates to the extent to which the return of a share is affected by changes in the market.

The determination of the “b” factor of an activity requires an analysis of the performance of the activity as compared to the performance of an appropriate stock index.

Therefore, in order to carry out the above analysis, it is necessary for the company to be listed on a stock exchange.

In order to determine the “b” factor in the case where the activity is not listed on a stock exchange, according to common practice, comparative studies are carried out on the basis of a sample of activities operating in similar sectors. The “b” factor is defined as the average of the values of the “b” factor of different activities operating in the same field, for each activity of a vertically integrated activity, separately.
Information about these activities is publicly available and can therefore be easily extracted using information from financial databases for each of the Production, Transmission and Distribution activities.
The “b” factor derived from these databases corresponds to the “b” factor of the equity of the activities and takes into account the percentage of loan dependency of each activity in the sample. Due to the different rates of loan dependency between the activities in the sample and the activity for which the “b” factor is to be determined, the average “b” factor of the sample is not a reliable indicator. Therefore, it is

necessary to convert the “b” factor of the sample’s equity into “b” factor of fixed assets, the average of which would adequately reflect the “b” factor of the activity’s fixed assets. Consequently, the “b” factor of fixed assets that has been set is converted (re-levering) to a “b” factor of equity using the loan dependency rate of each activity and the applicable tax rate.

2.5 R_d - Cost of Debt

The cost of debt is equal to the average interest rate paid by an activity on the current debt, which finances the cost of loans, bonds, or other forms of debt as a percentage. Together with the cost of capital, it constitutes the capital structure of the activity.

The cost of debts must be calculated for each activity of a vertically integrated activity separately, taking into account the debts received by each activity. The total borrowing cost is calculated and presented in the annual audited financial statements of the Company.

Given the need to calculate the WACC for all activities, the ideal approach should be based on the detailed separation of the debts (loans) and the relevant interest rate of the activity in the activities of Production, Transmission and Distribution, while the calculation of the interest rate should be carried out separately for each activity.

2.6 Effective tax rate (T c)

The effective tax rate of an activity is the weighted tax rate on the basis of which the pre-tax profits are taxed. It is calculated by dividing the total tax expenses of the activity by the profit before taxes. It is noted that all the tax liabilities of the company are taken into account, not only the current corporate tax and consequently the Effective tax rate may be higher than the corporate tax rate. However, for the sake of simplification, it is common practice to use the corporate tax rate as the actual tax rate.

2.7 Capital structure of the company

Finally, the capital structure of an activity, i.e. the separation between Equity and Debt, is by definition the basis for the calculation of the WACC. The percentage that characterizes the capital structure is the debt ratio (loan dependency ratio) calculated as the total debt through the total equity as determined in the balance sheet. However, the percentages of Debt and Equity by Total Capital (D / (D + E), E / (D + E)) are used in the calculation of the WACC.

As a consequence, each Vertically Integrated activity must separate Equity and Debt per activity for which the in the calculation of the WACC is calculated.

Annex 3: Operating Part of Allowed Revenue

3.1 Operating costs are the costs incurred by the regulated activities on a continuous, daily basis to carry out its business activities. Operating costs include elements such as maintenance, security, management, ancillary services, protection, consulting, legal services, insurance, call center, control center, human resources (HR), training and information technology (IT). Operating costs will only include items that are spent directly and are not capitalized according to accounting rules.

3.2 CERA determines in advance separate compensation for operating expenses for each activity performing the following activities: transmission (ownership of fixed assets), transmission (system operation), distribution (ownership and operation) and where the company holds a dominant position, generation and supply. For each of these activities, operating expenses are divided into two categories:

- operating costs on which the activity is deemed to exercise effective control ("controllable operating costs"); and
- operating costs on which the activity is deemed not to exercise effective control ("non-controllable operating costs").

3.3 In addition to the operating costs for which the compensation is determined in advance by CERA, the regulated activity may incur costs for the following:

- activities which are regulated but whose costs are directly recovered by customers, and/or
- activities that are not regulated.

3.4 The operating costs for such activities as explained in paragraph 3.16 below are totally excluded from the allowed revenue ("excluded operating costs").

Controllable operating costs

3.5 In general, the majority of operating expenditure items, such as maintenance and IT costs, are treated as controllable. The categorization of controllable operating costs proposed by CERA is presented in Table 1 below. This list may not include all possible controllable operating costs and is adjusted by CERA together with each regulated activity in order to obtain a final list of controllable operating costs for each regulatory review period.

- Each regulated activity declares to CERA its actual controllable operating costs at the end of each year and its comparison with its budgeted operating costs.

Table 1. Indicative list of controllable operating costs

Transmission (ownership of fixed assets)	Transmission (system operator)	Distribution (ownership of fixed assets)	Distribution (system operator)	Generation	Supply
Payroll[1]	Payroll	Payroll	Payroll	Payroll	Payroll
Contractors[2]	Contractors	Scheduled maintenance	Contractors	Contractors	Contractors
Scheduled maintenance	IT	Contractors	IT	Operations and maintenance	Sale of products and advertising
Repair of faults	Insurance	Repair of faults	Insurance	IT	IT
IT	Telecommunications	Logging	Telecommunicatio ns	Insurance	Insurance
Insurance	Legal services	IT	Legal services	Telecommunicatio ns	Telecommunications
Telecommunications	Facilities	Insurance	Facilities	Legal services	Legal services
Legal services	Professional Services	Telecommunications	Professional Services	Corporate Expenditure	Facilities
Facilities	Corporate Expenditure	Legal services	Management of fixed assets	Other general expenses of the activity	Corporate Expenditure

Professional Services	Other general expenses of the activity	Facilities	Corporate Expenditure		Other general expenses of the activity
Management of fixed assets		Professional Services	Other general expenses of the activity		
Corporate Expenditure[3]		Management of fixed assets			
Other general expenses of the activity [4]		Corporate Expenditure			
		Other general expenses of the activity			

Note 1: "Corporate Expenditure and other general expenditure of the activity" is distributed among the various regulated activities. regulated activities propose a methodology for allocating these costs. CERA examines and approves the methodology proposed by the regulated activities. **Note 2**: The expenditure figures in this table do not necessarily exclude each other. For example, there may be payroll costs associated with fault repairs (e.g. in relation to engineers' salaries). The philosophy of CERA for the collection of expenditure in different ways is to make clear the way in which the expenditure of the regulated activities are established and influenced by the management choices. On the basis of understanding the costs of the regulated activities, CERA shall decide how appropriate compensation may be determined.

1 The Payroll includes all staff costs

2 Contractors include any expenditure associated with work which regulated activity may have outsourced to subcontractors.

3 "Corporate Expenditure" includes expenditure for the support department, management, customers (issuing customer invoices, call center, account management), management, etc.

4 "Other general expenses of the activity " include stationery, printing, postage, etc.

3.6 Prior to the commencement of each regulatory review period, each regulated activity shall submit a claim for reimbursable controllable operating expenses for the forthcoming regulatory review period. The regulated activities provide a clear justification for the compensations claimed (clearly indicating the rationale behind any possible increase in expenditure in the previous regulatory review period). CERA verifies the evidence provided by the regulated companies.

3.7 The compensation of controllable operating costs of the regulated activity for the base year for each regulatory review period shall be based on an assessment of the following elements of each activity:

- the demand for controllable operating costs for the next regulatory review period; and
- the controllable operating costs over the previous regulatory review period.

3.8 CERA may set the effective compensation of the controllable operating costs of the base year at a level lower than the actual controllable operating costs during the previous regulatory review period. These possible reductions in the operating costs of the base year are referred to as a P0 cut. This is performed in order to take account of historical inadequacy (low performance) or to exclude, for example, the costs associated with individual events during the previous regulatory review period. Also, upon a detailed justification, increases in some parts of the controllable operating costs may be justified in specific cases.

3.9 When the effective compensation of the base year for the controllable operating costs is determined, CERA makes a calculation using the formula %CPI-X, where:

- The Consumer Price Index (CPI) is a variable for inflation and
- The efficiency factor (or factor X) represents the savings that the activity is reasonably expected to achieve in the future thanks to productivity increases over time.

3.10 Prior to the commencement of each regulatory review period, CERA shall set the efficiency factor (or factor X) for the reimbursable operating costs of each regulated activity applicable to the next regulatory review period.

3.11 This efficiency factor may be revised in future regulatory review periods based, inter alia, on:

- an assessment of the dynamic efficiency coefficients set by other regulatory authorities in Europe and/or
- an assessment of the regulated activity itself on its ability to achieve dynamic efficiency savings over time.

3.12 CERA rewards the regulated activity for any positive performance in relation to the compensation of the controllable operating costs. Specifically, the regulated activity will enjoy a percentage of Xi%[8] ≤ 100% of the respective positive performance in relation to the compensations for the controllable operating costs as additional revenue, distinct for each eligible type of tariff i, i.e. T-H, T-NH, T-NM, T-NL, and T-MET. The remaining part of the positive performance (equivalent, of the achieved savings of controllable operating costs), i.e. 100-Xi%, will be directed towards the proportional reduction of the respective types of valuations (T-H, T-NH, T-NM, T-NL, T-MET) for customers through suppliers representing them for the remaining years of the regulatory review period.

In case of negative performance, the regulated activity will be charged with the total (100%) cost of the negative performance in relation to the pre-determined target set by CERA for controllable operating costs.

The individual discrete rates X_i% for each eligible type of tariff will be determined by decision of CERA at the beginning of each review period and will be valid for the entire regulatory review period. At the start of the next review period, CERA will redefine the compensations for the operating controllable costs of each regulated activity, taking into account, inter alia, the cost effectiveness of the operating costs during the previous regulatory review period.

The audit of the implementation of the above incentives to reduce controllable operating costs will be carried out on an annual basis. It is noted that in no case is an annual adjustment of the corresponding category of allowed revenue of the regulated activity, i.e. T-H, T-NH, T-NM, T-NL, and T-MET, which are determined in accordance with Chapter 5.

The above incentive methodology for reducing the controllable operating costs of each regulated activity will be applied after the transition period of N_i years, distinct for each eligible type of tariff *i*, i.e. T-H, T-NH, T-NM, T-NL, and T-MET, to afford the necessary time:

(a) for the regulated activity to adapt its cost base so that it can achieve the set objectives; and

(b) for the full and competitive operation of the new electricity market.

The value of parameter Ni for each type of tariff is set out in Annex 4.

Non-controllable operating costs

Non-controllable operating costs are related to items such as fees and operating license taxes, on which the regulated activity does not exercise any control. The categorization of controllable operating costs proposed by CERA is presented in **Table 2** below. This list may not include all possible non-controllable operating costs and is adjusted by CERA together with each regulated activity in order to obtain a final list of non-controllable operating costs for each regulatory review period.

[8] During the first N_i years of application of this Regulatory Decision all the above percentages X_i% are equal to 100%

Table 2. Categories of non-controllable operating costs

Transmission (holder of fixed assets)	Transmission (system operator)	Owner and Distribution Operator	Generation	Supply
Regulatory fees[9]	Regulatory fees	Regulatory fees	Regulatory fees	Regulatory fees
Local authority fees[10]	Compensation between Transmission System Operators	Local authority fees	Cost of fuel[11]	Network charges[12]

9 Regulatory fees include all annual payments made by the regulated activity to CERA.

10 Local authority fees shall include all annual business property fees paid by the regulated activity to the local authority

11 CERA monitors the price and quantity of each fuel used in order to determine whether the fuel mix of the regulated company is efficient. Fuel costs are considered as non-controllable, to the extent that the regulated activity can demonstrate that it has used the most efficient fuel mix. If CERA considers that the fuel mix of the regulated company is inefficient, then part of the cost of fuel may not be allowed.

12 To the extent that these charges have to be paid by the provider to the network owners.

Road works[13]	Ancillary Services	Road works	Capacity margin[14]	Charges for the purchase of energy from the Wholesale and Balancing Markets
Pension costs[15]	Pension costs	Pension costs	Environmental obligations	PSO
Taxes	Taxes	Taxes	Ancillary Services	Charges for the purchase of electricity from RES as part of National Subsidy Plans
			Pension costs	Charges for the supply of Ancillary Services
			Taxes	Taxes
				Charges for the purchase of certificates of origin

13 Road works shall include all the annual payments to be made by the regulated activity to the owners and/or cultivators of the land in order to cover the financial impact from the installation of the equipment or mechanism of the regulated activity on their land.

14 If CERA requires the maintenance of a change in the capacity margin by a dominant producer, then it can consider the required increase in the relevant cost as non-controllable.

15 Some items may be controllable (and included in payroll), while other items such as legacy system costs may be non-controllable.

3.13 Prior to the commencement of each regulatory review period, each regulated activity shall submit a claim for reimbursable non-controllable operating expenses for the forthcoming regulatory review period. The regulated activities provide a clear justification for the compensations claimed (clearly indicating the rationale behind any possible increase in expenditure in the previous regulatory review period). CERA verifies the evidence provided by the regulated companies.

3.14 The compensation of controllable operating costs of CERA for each regulatory review period shall be based on an assessment of the following elements of each activity:

- the request by the activity for non-controllable operating costs for the next regulatory review period; and
- the non-controllable operating costs over the previous regulatory review period.

3.15 CERA shall not provide an incentive for a positive performance or an efficiency factor for the non-controllable operating costs, as it considers that the regulated activity does not exercise management control over these costs. Consequently, non-controllable operating costs are passed on to customers. In other words, if the non-controllable operating costs of the regulated activity are higher (or lower) than those allowed by CERA, then they may be passed on to customers by adjusting the prices on an annual basis. The regulated activity should at the end of each year of the regulatory review period submit to CERA a list of actual non-controllable operating costs and a comparison thereof with the budgeted non-controllable operating costs with a reasoned request to forward these differences (positive or negative) to customers with the submission of a report.

Excluded operating costs

3.16 In addition to the operating costs for which the compensation is determined in advance by CERA, the regulated activity may incur costs for the following:

- activities which are regulated but the cost of which is directly recovered by customers (including, for example, customer connections) and/or
- activities that are not regulated

3.17 The operating costs for such activities are totally excluded from the allowed revenue ("excluded operating costs"). CERA shall check the scope of the excluded costs of the regulated activity in future regulatory review periods to ensure that new activities falling under this category are excluded from the allowed revenue in the future.

3.18 Although all excluded operating costs are excluded from the allowed revenue, their declaration to CERA is required. CERA's instructions on the submission of declarations include a description of these costs and the defined periodicity of the declaration.

CERA points out that certain “Corporate Costs” and “General costs of the company” as defined in **Table 1** above. **Categories of controllable operating costs** should also be allocated between regulated and unregulated activities of regulated activities. regulated activities propose a methodology for allocating these costs. CERA examines and approves the methodology proposed by the regulated activities.

Annex 4: Tariff Parameters

CERA shall review and determine from time to time the parameters of the following table.

Table 3. Tariff parameters

Parameter description	Reference	Price
Duration of the regulatory review period	Paragraph 5.2	5 years
Proportion of allowed transmission revenues recovered through power charges	Paragraph 7.19	0%
Proportion of allowed distribution revenues (MV) recovered through power charges	Paragraph 7.32	0%
Proportion of allowed distribution revenues (LV) recovered through power charges	Paragraph 7.40	0%
Allowed mark-up for commercial and accounting management services	Paragraph 7.56	20
Parameter Ni for T-H, T-NH, T-NM, T-NL, and T-MET.	Annex 3 - Paragraph 3.12	5 years

Annex 5: Methodology for calculating the Electricity Tariff of Wholesale T-H

Based on the provisions of paragraphs 7.8 and 7.10, the calculation of T-H is expressed mathematically as follows:

$$\Delta X_{\varepsilon,\eta} = \overline{OKE}_{\varepsilon,\eta} + \overline{OKI}_{\varepsilon,\eta} + \overline{\Pi OK}_{\varepsilon}$$

with:

$$\overline{OKI}_{\varepsilon,\eta} = \frac{2 \cdot \overline{\Pi A\Phi}_{\varepsilon,\eta}}{\sum_{\eta\in\varepsilon} \overline{\Pi A\Phi}_{\varepsilon,\eta}} \cdot \varDelta OKI_{\varepsilon}$$

$$\overline{\Pi OK}_{\varepsilon} = \frac{1}{\overline{EN\varDelta\Sigma}_{\varepsilon}} \cdot \left(EE_{\varepsilon}^{-} - \sum_{\eta\in\varepsilon} \left(\overline{OKE}_{\varepsilon,\eta} + \overline{OKI}_{\varepsilon,\eta} \right) \cdot \overline{EN\varDelta\Sigma}_{\varepsilon,\eta} \right)$$

where:

$AA\Phi$	Load discharge value, in €/MWh
$A\varDelta A\Phi_{\varepsilon}$	Expected duration of load discharge (LOLE), in hours/year
$\varDelta OKI_{\varepsilon}$	Administratively defined Limit Power Cost, in €/MW/year (€ 72,820/MW/year for year ε)
$\Delta X_{\varepsilon,\eta}$	Wholesale tariff for half hour η of the year ε, in €/MWh
$\overline{EE}_{\varepsilon}^{-}$	allowed revenue of the regulated activity for year ε impaired on net market revenue (based on estimates for year *e* and measurements for year *e*-2), in €
$\overline{EN\varDelta\Sigma}_{\varepsilon,\eta}$	Estimate (in year *e*-1), for half hour η of year ε, of the sale of electricity to the regulated producer through bilateral contracts, in MWh
$\overline{EN\varDelta\Sigma}_{\varepsilon}$	Estimate (in year *e*-1), for year ε, of the sale of electricity to the regulated producer through bilateral contracts, in MWh
$MOK_{\varepsilon,\eta}$	Long-term limit cost of the electricity system in Cyprus for half hour η of year ε, in €/MWh
$\overline{OKE}_{\varepsilon,\eta}$	Estimate, for half hour η of year ε, of the energy limit cost of the electricity system of Cyprus (calculated by annual simulation of the operation of the system, based on the forecast of the load and the estimated actual limit cost of the production units (the strategies of the producers are ignored), in year *e*-1) , in €/MWh

$\overline{OKI}_{\varepsilon,\eta}$	Estimate (in year *e*-1), for half hour η of year ε, of the power limit of the electricity system of Cyprus, in €/MWh
$\overline{\Pi A\Phi}_{\varepsilon,\eta}$	Estimate (in year *e*-1), for half hour η of year ε, of the probability of load discharge into the electricity system of Cyprus (based on a reliability study), in p.u.
$\overline{\Pi OK}_{\varepsilon}$	Adaptation of the limit energy and power costs for the recovery of the regulated producer's allowed revenue for year ε (based on estimates), in €/MWh

Justification of the mathematical formula for the definition of the Marginal Cost ($\overline{\boldsymbol{OKI}}_{\boldsymbol{\varepsilon,\eta}}$)

The Long-Term Limit Cost (MOK) of an electricity system for any half hour η of year ε is defined by the short-term energy limit cost in the case of adequate production capacity in half hour *η* and by the value of the load discharge (*ΑΑΦ*) in the case of load discharge in half hour *η*. The corresponding probabilities are the first terms of the two products of the following MOC definition relationship.

$$MOK_{\varepsilon,\eta} = \left(1 - \Pi A\Phi_{\varepsilon,\eta}\right) \cdot OKE_{\varepsilon,\eta} + \Pi A\Phi_{\varepsilon,\eta} \cdot AA\Phi$$

In approximation $\left(\Pi A\Phi_{\varepsilon,\eta} \ll 1\right)$, the above relation is written as follows:

$$MOK_{\varepsilon,\eta} = OKE_{\varepsilon,\eta} + \Pi A\Phi_{\varepsilon,\eta} \cdot AA\Phi$$

Its calculation $AA\Phi$ arises from the long-term market equilibrium condition, which is defined as:

$$AA\Phi \cdot A\Delta A\Phi_{\varepsilon} = \Delta OKI_{\varepsilon}$$

or, equivalently,

$$AA\Phi = \frac{\Delta OKI_{\varepsilon}}{A\Delta A\Phi_{\varepsilon}}$$

On the basis of the definition of the Expected Load Discharge Length, the following applies:

$$A\Delta A\Phi_{\varepsilon} = \frac{1}{2} \cdot \sum_{\eta \in \varepsilon} \Pi A\Phi_{\varepsilon,\eta}$$

From the combination of the above relations, it follows that $AA\Phi$ as:

$$AA\Phi = \frac{2 \cdot \Delta OKI_{\varepsilon}}{\sum_{\eta \in \varepsilon} \Pi A\Phi_{\varepsilon,\eta}}$$

and finally that:

$$OKI_{\varepsilon,\eta} = \frac{2 \cdot \Pi A\Phi_{\varepsilon,\eta}}{\sum_{\eta \in \varepsilon} \Pi A\Phi_{\varepsilon,\eta}} \cdot \Delta OKI_{\varepsilon}$$