REPUBLIC OF ARMENIA
ELECTRICITY MARKET TRANSMISSION NETWORK CODE

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SECTION 1. GENERAL PROVISIONS

CHAPTER 1. SUBJECT AND DEFINITIONS

1. The Republic of Armenia (RoA) Electricity Market Transmission Network Code (hereinafter, the ETN Code) shall regulate planning of the electricity system's development process, electricity system short-term planning, electricity system operational management and dispatch, and connection of new capacities to the grid, as well as define the requirements set for electricity Metering Complexes in the electricity system and procedures focused on the improvement of efficiency of electricity system operations.
2. The main definitions used in the ETN Code:

1)	**Transient state**	The regime of Electricity system operation characterized by a significant change in parameters that takes the system from one state to another one.
2)	**Primary Reserve**	Active capacity of the generating unit operating synchronously with the electricity system that can be automatically loaded or shed accordingly in case of deviation from the defined frequency value.
3)	**Commercial Metering**	Metering of electricity (capacity) quantities and provided services subject to payment within the framework of trading relations of the Wholesale Electricity Market (hereinafter, WEM) Participants.
4)	**Asynchronous state**	Transient state of the Electricity system that results in disturbance of the synchronous operation of the parts of the system.

5)	**Automated Load Shedding Program**	Automated load shedding program of the electricity system implemented by the ESO in Emergency Situations through the action of the system automated devices.
6)	**Generator**	An entity that is eligible for electricity (capacity) generation and actually performs generation activity, except for a plant being in the stage of testing and commissioning, and in case of connecting the Generator to the network, the entity that applied for such a connection.
7)	**Export Point**	Crossing point of the interconnection line and the state border, where the export of electricity is carried out.
8)	**Distribution Network**	A unified system of electricity distribution lines, substations, and other facilities controlled and operated by the Distributor.
9)	**Distributor**	An entity holding a license for electricity (capacity) distribution.
10)	**Normal State**	Operational parameters of the electricity system in real time, when they are within the ranges of the reliability and security indicators stated in Annex 1 of the ETN Code (hereinafter: RS Indicators) defined for the normal state.
11)	**Normal scheme**	Operative disposition of the Electricity system that ensures the maintenance of the Normal State.
12)	**Transaction**	An agreement between the WEM Trade Participants in respect of electricity trading in all segments and components of the WEM or a direct contract signed with a foreign physical or legal entity on the export of electricity or on the import of electricity to be sold in the WEM or to satisfy its own demand.
13)	**Universal Supplier**	An entity holding a universal supplier license.
14)	**Secondary Reserve**	The part of the active capacity regulation range (increased or reduced) of the generator operating synchronously with the electricity system that is used for frequency control, compensation of capacity imbalance, elimination of overloading of transit connections, and restoration of the Primary Reserve during the primary regulation.

15)	**Tertiary Reserve**	The reserve capacity of the generator in the electricity system in the cold reserve, used to replace Primary and Secondary reserves.
16)	**Ten-Year Network Development Plan (TYNDP)**	The development plan of the Transmission Network described in the Section 2 of the ETN Code.
17)	**EDN Code**	The Republic of Armenia Electricity Market Distribution Network Code approved by the Commission.
18)	**Security of the Electricity System**	The property of the electricity system to ensure operational parameters that are safe for any of its components that are part of the system or facilities connected to the system.
19)	**Dynamic (transient) Stability of the Electricity System**	The ability of the electricity system to move to the Sustainable or Normal state after a significant change to the state.
20)	**Reliability of the Electricity System**	The property of the electricity system to ensure generation, transmission, distribution, and supply of the electricity to customers within the specified range of technical parameters.
21)	**Static Stability of the Electricity System**	The ability of the electricity system to move to the Sustainable or Normal state after minor disturbances.
22)	**Annual Adequacy Forecast (AAF)**	A complex of annual forecasted indicators of electricity consumption, losses and own needs, generation, import, and export defined in the WEM Rules.
23)	**Electricity System**	The complex of installations for electricity generation, transmission, distribution, and consumption, as well as equipment and devices for their management, relay protection, system automation, and communication that are under operational management and/or control (hereinafter, referred to as operational subordination) of the ESO.
24)	**Data Acquisition System (DAS) Chief Administrator**	An authorized person appointed by the EMO responsible for the management of the Automated Data Acquisition System in the Wholesale Electricity Market.

25)	**DAS Administrator**	An authorized person appointed by the Utility-Scale Plant, Transmitter, Distributor and Qualified Customer through whom the DAS Chief Administrator manages the DAS.
26)	**WEM Rules**	The Wholesale Electricity Market Trading Rules of the RoA.
27)	**WEM Participant**	Generator, Universal Supplier, Supplier, Trader, Qualified Customer, Transmitter, Distributor, ESO, and EMO.
28)	**WEM Contract**	A contract between WEM Participants for participation in the WEM.
29)	**Emergency State**	Real-time operational parameters of the Electricity system when they are within the range of RS Indicators defined for the Emergency state.
30)	**Dispatch**	Universal group of processes and activities required for electricity system technological management with a purpose of ensuring opportunities for electricity generation, import, export, and transit, as well as for forecasted consumption volumes declaration and planning, and for covering the entire electricity demand in real time to ensure supply of electricity of the required quality in compliance with the RS Indicators.
31)	**Transmission Network**	The unified system of electricity transmission lines (including substations and other facilities), under the management and operation of the Transmitter, through which electricity is transmitted to the distribution network and customers, exported (imported), and/or transited to a third country.
32)	**Transmitter**	An entity holding an electricity (capacity) transmission license.
33)	**Utility-Scale Customer**	A Qualified Customer with installed capacity of 10 MW and above, connected to the transmission or distribution network.
34)	**Utility-Scale Plant**	A power plant with installed capacity of 10 MW and above, connected to the transmission or distribution network.

35) **System Services** — Services provided by WEM Participants in cases and procedures defined by the ETN Code for the reliable and safe operation of the electricity system.

36) **Dispatcher of the ESO** — An authorized entity who performs dispatching services on behalf of the ESO.

37) **Electricity System Operator (ESO)** — An entity holding the license for provision of Electricity System Operator services.

38) **Commission** — The Public Services Regulatory Commission of the RoA.

39) **Metering Point** — Commercial and control metering points specified in the WEM Contract.

40) **Metering Complex** — A set of combined devices envisaged for measurement and settlement of electricity (capacity), including current and potential transformers, electricity meters, impulse sensors, modems, adders, connection wires, and uninterruptible electricity feeding devices ensuring autonomous reliable feeding for at least 1.5 hours, which are connected to each other according to the scheme approved by design.

41) **Settlement Period** — A settlement period of 60 minutes' duration.

42) **Balancing Service Provider Generator (BSP)** — A Generator providing balancing services under an electricity generation license and a wholesale trading license, as defined in the WEM Rules.

43) **Balancing** — A set of processes and activities required for technological management of the electricity system implemented by the ESO to cover the entire electricity demand in real time, which will ensure electricity supply of defined quality maintaining RS Indicators.

44) **Connection Point** — A physical point of the Transmission Network, to which the generation facility and/or the consumption system of the Applicant are connected.

45) **Connection Contract** — An agreement signed between the Transmitter and the Applicant on connection of the generating facility and/or the consumption system of the Applicant to the Transmission Network.

46)	**Connection Reference or Reference**	A document on the possibility of connecting to the Transmission Network provided to the person intending to obtain a license for electricity generation.
47)	**Connection Capacity**	Capacity of a new or reconstructed facility and equipment being connected to the Transmission Network.
48)	**Import Point**	A crossing point on the interconnection line, through which import of electricity is implemented.
49)	**Normative contingency**	Failures in the Electricity system that are mandatory to study for assessment of reliability and security.
50)	**Electricity Market Operator (EMO)**	An entity holding the license for provision of electricity market operator services.
51)	**Qualified Customer**	A customer recognized by the EMO as qualified based on the criteria defined by the WEM Rules.
52)	**Contingency**	Failure of the normal state of Electricity system operation.
53)	**Parameters of the States**	The values for capacity, voltage, current, and frequency of the Electricity system.
54)	**Boundary Point**	The border of balance ownership of electric installations of the WEM Trade Participants.
54.1)	**Renewable Energy source**	Non-fossil renewable energy sources (wind, solar, hydro, geo-thermal, biomass, biogas and other) suitable for generation of electricity and (or) thermal energy.
55)	**Technical Conditions**	Technical requirements for connection to the Transmission Network at least cost, to ensure connection of facilities at technical parameters defined in the application for connection and metering of electricity.
56)	**Available capacity**	Maximum capacity subject to dispatch by the ESO, which is determined by reducing the capacity defined in accordance with Annex 2 of the ETN Code by the capacity of limitations resulting from climatic conditions at thermal and nuclear power plants (external air temperature, humidity, location altitude), water flow and pressure at hydropower plants, as well as the deterioration of main equipment, thermal load, and residual physical resources.

CHAPTER 2. OBJECTIVES OF THE ETN CODE

3. The objectives of the ETN Code are:
   1) To regulate development planning and the normal operation of the electricity system;
   2) To regulate within the electricity system the activities of the ESO, Generators (including Utility-Scale Plants), the Transmitter, the Universal Supplier, Suppliers, the Distributor, the EMO, Qualified Customers, and Applicants as well as to define the rights and obligations of all those mentioned, enabling the ESO to ensure secure and reliable, effective and transparent operation of the grid, thus reducing security threats to the electricity system;
   3) To provide open, transparent, and non-discriminatory access and use of the transmission system;
   4) To establish an effective system for settlement of disputes among WEM Participants and Applicants.

CHAPTER 3. INFORMATION SUBMISSION AND NOTIFICATION

4. The exchange of information among the WEM Participants, as well as the submission of documents, shall be performed in a proper way as defined in Provision 5 of the ETN Code.
5. Within the framework of the ETN Code, the exchange of information among the WEM Participants as well as the submission of documents shall be deemed appropriately performed if the information has been sent by registered letter with a notice of delivery or by other means securing the integrity of the message (including sending a message to a phone number specified by the WEM Participant or Applicant), or by electronic communication systems (including to the email specified by the WEM Participant or Applicant), as well as through other electronic communication means defined by legislation, or if it has been delivered with a

mail delivery confirmation, unless otherwise specifically mentioned in the ETN Code. In case of notification through the Market Management System (MMS), the information presented to the EMO shall be deemed notified by the given participant to other WEM Participants whom it may concern.

6. The WEM Participant shall be liable for the accuracy of information provided in the WEM.
7. Where inaccuracies are revealed in the information provided by a WEM Participant, the person who revealed those inaccuracies shall, within no more than 3 business days after the inaccuracies have been revealed, submit the information to an authorized person and the latter shall make appropriate corrections within 1 business day after being notified.
8. In cases provided for by the ETN Code, the EMO and ESO shall ensure the complete publication of information presented by WEM Participants.
9. A WEM Participant shall respond to the inquiries, applications, complaints, or suggestions of other WEM Participants within 5 business days upon receiving them, unless another term is defined by the ETN Code for the specific cases.
10. Information shared by WEM Participants with each other shall be in the public domain if it is not deemed confidential in accordance with the Law or if the WEM Participant who presented that information does not consider it confidential and did not mark it as "Confidential information" according to the RoA legislative requirements.
11. A WEM Participant shall be eligible to disclose confidential information only in cases and procedures defined by the law and shall bear responsibility for violating legislative requirements regarding the information's confidentiality.
12. Any data, record, or document provided in the context of the ETN Code shall be preserved for at least 5 years, but not less than a period defined in the legislation for storage of such type of documentation.

CHAPTER 4. WEM PARTICIPANTS' RESPONSIBILITIES, DISPUTE (DISAGREEMENT) RESOLUTION

13. A WEM Participant shall bear responsibility for non-fulfillment or inadequate fulfillment of the provisions of the ETN Code by the Law on Energy (hereinafter, the Law) and in the procedures defined by the WEM Contract.
14. A WEM Participant shall not be responsible for violations defined in the ETN Code if they happened due to force majeure circumstances.
15. In terms of the ETN Code, any circumstance or event (or after-effect of that event) is considered a force majeure situation if it led (or may lead or will lead) to non-fulfillment or inadequate fulfillment of obligations defined by the ETN Code and at the same time is characterized by the features stated below:
    1) Is out of control of the WEM Participant;
    2) The WEM Participant undertook all possible actions and efforts (including precautional, alternative, legally defined) to prevent, weaken, eliminate, or avoid the influence of those circumstances (after-effects);
    3) The WEM Participant notified the other party about such circumstances in the shortest possible time but not later than within 10 days after being informed of the circumstance.
16. In terms of the ETN Code, force majeure includes but is not limited to the following situations:
    1) Natural and man-made calamities; epidemics; acts of God (including floods, earthquakes, hurricanes, tornados, thunderstorms, heavy rains with lightning, snowstorms and landslides); nuclear, chemical, or biological contamination; strikes; and public disorders;
    2) Rebellions, terroristic acts, wars, invasions, armed conflict, actions of foreign enemies, and blockades that take place on or involve the territory of the RoA and could not be reasonably predicted;

3) An act, activity, or inactivity of a state and municipal agency or other authorized body, due to which no permission or right was issued or extended to facilitate fulfillment of obligations, or due to which fulfillment of obligations was hindered, on condition that the WEM Participant acted in compliance with the RoA legislation.

17. Where a dispute (disagreement) arises between the WEM Participants, the parties shall resolve it through negotiations.
18. The EMO and the ESO shall facilitate alternative dispute resolution within the framework of their jurisdictions.
19. If a dispute (disagreement) is not settled by the parties, any party may apply to the Commission requesting that it resolve the dispute within its jurisdiction, as well as may file a suit at a competent court unless the parties have agreed to submit their dispute to arbitration.

SECTION 2. LONG-TERM PLANNING

CHAPTER 5. GENERAL PROVISIONS

20. The purpose of long-term planning is to develop an economically justified least cost TYNDP, which will ensure the continued reliable and secure operation of the electricity system.
21. Long-term planning is implemented based on requirements of the Law, this section, and the technical regulations, as well as the RS Indicators.
22. The implementation of the following measures and functions in the electricity system shall be reasonably justified in the course of the long-term development planning:
    1) Construction of new and decommissioning of the existing facilities;
    2) Reconstruction or upgrading of the existing facilities;
    3) Modernization of relay protection and automation devices;
    4) Replenishment and modernization of system automation devices;
    5) Re-configuration of the Transmission Network topology;
    6) Introduction of new technologies.
23. The long-term planning process shall comprise the following stages:
    1) Data collection and processing;
    2) Studies required for long-term planning;
    3) Modeling;
    4) Development and approval of the TYNDP.
24. The ESO and the following WEM Participants shall participate in the process of long-term planning (hereinafter, ELTP Participants):
    1) Utility-Scale Plants;
    2) Transmitter;
    3) Distributor;
    4) Utility-Scale Customers.

25. The TYNDP shall be prepared by the ESO once per 2 years, considering therein the development of the Electricity system within the next 10-year period.
26. To develop the TYNDP, the ESO may engage independent experts or organizations.
27. All actions and projects proposed in the TYNDP shall include assessment of the time schedule for the construction and rehabilitation works, which will incorporate the time schedules for obtaining permissions from the state, municipal self-government, and regulatory bodies for the planning and design of such projects and for starting construction works.

CHAPTER 6. LONG-TERM PLANNING STANDARDS AND CRITERIA

28. The long-term planning process shall consider changes in the electricity consumption and generation levels and structure, new technologies, changes to prices of energy carriers, and any other possible scenarios and situations.
29. The long-term planning process shall incorporate assessments of electricity system operation regimes by seasons (winter, spring, summer, autumn).
30. The long-term planning process shall evaluate possible risks of violation of the normal operation of the system and develop measures aimed at minimizing their negative consequences.
31. While developing the TYNDP, the ESO shall ensure that RS Indicators of the electricity system are adequately maintained in the event that any single element of a multi-element group is lost.
32. Various preparatory arrangements to ensure operational security shall be addressed in the long-term planning process in case of Contingencies deemed to be exceptional from the viewpoint of RS Indicators of the electricity system. The choice of preparatory measures shall depend on the comparative analysis of the technical

and economic factors and shall be separately explained in the TYNDP, taking into account the following:

1) The probability of occurrence of that type of Contingency;
2) The possible consequences of that type of Contingency;
3) The expenses incurred in order to exclude the emergence of such Contingencies;
4) The cost of introducing protective measures required to prevent the extension of the Contingency.

33. The long-term planning shall be carried out in such a way:
    1) To maintain all parameters defined by the RS Indicators for the Normal State for forecasted regimes of generation and consumption in Electricity System;
    2) To maintain the parameters of the Normal State defined by the RS Indicators in cases of a design basis contingency at any of the electricity system elements (generator, line, transformer, etc.);
    3) To be capable of restoring the Normal State of operation after any type of contingency, in parameters and time limits defined by RS Indicators parameters.

34. The following shall be considered during the long-term planning process:
    1) Electricity generation, transmission, distribution, and interconnection electricity flows through the transmission lines with neighboring countries;
    2) Information about the connection of new as well as reconstructed facilities to the Transmission Network;
    3) The state policies in regard to the energy sector, including effective use of water resources, promotion of renewable resources development, mitigation of environmental effects, etc.

CHAPTER 7. DATA COLLECTION AND PROCESSING

35. The ESO shall collect, process, and summarize the data and information required for long-term planning.
36. For long-term planning purposes, the ESO shall develop the forms of information subject to submission by the relevant ELTP Participants.
37. To receive data and information for long-term planning purposes, the ESO shall apply to the ELTP Participants and, within 20 business days of receiving the application, they shall provide the necessary information to the ESO.
38. In cases when an ELTP Participant intends to take their facilities that are a part of the electricity system out of operation, they shall notify the ESO at least 2 years prior to such action.
39. The ESO may request that the ELTP Participants provide additional information in order to check the accuracy of the planning data. The additional information requested shall be submitted to the ESO within 10 business days upon the receipt of the request.
40. When an ELTP Participant identifies an inaccuracy in the information provided for the TYNDP, it shall notify the ESO in writing within 3 business days after revealing inaccuracies.

CHAPTER 8. STUDIES AND MODELING REQUIRED FOR LONG-TERM PLANNING

41. The electricity system's long-term planning within the framework of the TYNDP shall be implemented based on the following studies:
    1) Assessment of the dynamics of the internal demand, import, and export;
    2) Assessment of the operation states and losses of the Transmission Network;
    3) In case of connection of new or reconstructed facilities to the grid, assessment of the impact of such connection on the grid;

4) Assessment of the timetable for commissioning of new facilities and remedial measures for elimination of deficiencies at the existing facilities;
5) Assessment of impact due to expected changes in the electricity and capacity demand;
6) Study ensuring load flows, short circuits, static and dynamic stability, and voltage levels at checkpoints;
7) Assessment of system performance during Normal and Emergency states pertinent to the electricity system;
8) Assessment of electricity system behavior during disturbances (deviations) and switching;
9) Study of potential congestions at network elements;
10) Assessment of capacity reserves (active and reactive) under synchronous and island operation regimes;
11) Any other assessment or study to ensure the reliable and secure operation of the electricity system in the future at economically justified least cost.

42. All studies required for the long-term planning of the electricity system within the framework of the TYNDP are performed through modeling. Modeling shows the impact of real objects, processes, and events on the electricity system's forecasted indicators. The electricity system development models are developed to evaluate the potential to cover the anticipated consumption demand in all sectors of the economy from domestic sources as well as electricity export and import opportunities.

43. The following fundamental assumptions shall be accepted for the purposes of modeling the electricity system in the context of the TYNDP:
1) Capacity demands are represented at peak, off-peak, and base load conditions for each third Wednesday and one non-business day of each month;
2) Energy and capacity demand are modeled for forecasted

internal consumption, export, and import, as well as transit modes;

3) Analysis is conducted to assess the impact that deviations from the forecasted demand may have on the electricity system modes;
4) Electricity system Dispatch shall be performed on an annual basis so that the electricity supply to customers can be ensured at least cost, considering the purchase guarantees to the Generators;
5) Scheduled maintenance outages of facilities and other limitations necessary for mode adjustments are taken into account;
6) Transmission facilities are modeled to consider the scheduled maintenance and construction outages and long-term forced outages;
7) Interconnected exchanges are modeled to study their impact on electricity system performance;
8) Relay protection and system automation parameters are modeled for the purposes of adjustments needed.

44. Modeling shall be performed for the main and alternative development scenarios of the electricity system—optimistic and pessimistic scenarios.
45. The electricity system characteristics to be modeled must comply with the established RS Indicators.
46. The modeling software used during electricity system long-term planning shall ensure the equivalent reproduction of actual processes.

CHAPTER 9. DEVELOPMENT AND APPROVAL OF THE TEN-YEAR NETWORK DEVELOPMENT PLAN

47. The ESO shall develop and approve the TYNDP in cooperation with the ELTP Participants.

48. The TYNDP shall include the results of all studies as defined in the requirements of Chapter 8 of the ETN Code and shall summarize the activities necessary to ensure the further reliable and secure operation of the electricity system at economically justified least costs for each year out of the 10-year planning period, by the following aspects:
    1) Electricity and capacity demand and supply forecast;
    2) Capacity reserve requirements of power plants;
    3) Technical parameters of the existing generating facilities, as well as decommissioning and reconstruction projects;
    4) Description of newly expected generating capacities and the preferable nodes for their connection;
    5) Description of Transmission Network development activities,
    6) Electricity import and export forecasted volumes;
    7) Electricity generation and consumption balance, including Transmission Network losses and electricity for own needs;
    8) Surplus or deficit of electricity and capacity generation, as well as reserve requirements.
49. The Utility-Scale Plants, Transmitter, and Distributor shall include the activities specified in the TYNDP in the investment programs, in parts and periods regarding each of them.
50. After the necessary data and information is collected, processed, and summarized as defined in Chapter 7 of the ETN Code, before October 15, the ESO shall publish the draft TYNDP on its official website and send a notification to the RoA Government authorized body, Commission, and ELTP Participants.
51. Within 20 business days following the receipt of the notification from the ESO as defined in Provision 50 of the ETN Code, the RoA Government authorized body, Commission, and ELTP Participants shall submit their suggestions and opinions to the ESO.
52. Within 20 business days after the suggestions and opinions with regard to the draft TYNDP have been provided, the ESO shall

summarize the presented suggestions and approve the TYNDP within 20 business days.

53. Within 5 business days following the approval, the ESO shall provide the approved TYNDP to the RoA Government authorized body and Commission and will publish it on the ESO website, notifying the ELTP Participants of that fact.

SECTION 3. SHORT-TERM PLANNING

CHAPTER 10. GENERAL PROVISIONS

54. The purpose of short-term planning is to plan the reliable and secure operation of the Electricity system on an annual basis.
55. During, short-term planning the following shall be considered:
    1) The annual schedule of the planned outages of the electricity system, including its adjustments on a monthly and daily basis (hereinafter, EPOS);
    2) The forecasted annual demand for electricity, including its adjustments on a monthly and daily basis (hereinafter, EDEM);
    3) The forecasted annual electricity generation mix, including its adjustments on a monthly and daily basis (hereinafter, EGEN);
    4) The forecasted annual Transmission Network losses, including their adjustments on a monthly and daily basis (hereinafter, ELTRANS);
    5) The annual reliability and security level of the electricity system, including its adjustments on a monthly and daily basis (hereinafter, ERSL).
56. The ESO shall collect, process, and summarize the data and information required for short-term planning. The list and reporting forms of data and information required for short-term planning to be submitted by relevant WEM Participants in compliance with the requirements of this Chapter shall be defined by the ESO.
57. The ESO may request additional information or clarifications from WEM Participants during short-term planning. WEM Participants shall provide additional clarifications to the ESO in procedures and within the deadline established in Chapter 3 of the ETN Code, unless a longer period is agreed upon by the parties.

CHAPTER 11. SCHEDULE FOR THE PLANNED OUTAGES

58. The ESO shall compile the EPOS based on the information on planned outages of electric facilities received from Utility-Scale Plants, the Transmitter, the Distributor (only for substations and electricity transmission lines directly connected to the Transmitter), and Utility-Scale Customers (hereinafter, ESTPO Participants).
59. The ESO shall compile the EPOS on an annual basis and shall adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
60. The ESTPO Participants shall provide the information on annual outages of their facilities for the following year to the ESO by June 1 of the given year, whereas the monthly and daily adjustments for annual information shall be provided as follows:
    1) By the 15th of every month for the following month;
    2) Each business day by 10:00 of the same day for the following second day, and if following days are non-business days, for those days and the next following business day as well.
61. The ESTPO Participants' information on annual, monthly, and daily planned outages of their electric facilities submitted to the ESO shall include at least the following:
    1) Description of the electric facility subject to the planned outage;
    2) Duration of the planned outage;
    3) Planned outage start and end dates;
    4) Justification for the planned outage.
62. The EPOS shall be compiled and adjusted by the ESO based on the information submitted by the ESTPO Participants as prescribed in Provision 61 of the ETN Code, as well as information on outages for cross-border transmission lines received from neighboring Transmission Network operators.
63. The ESO, while compiling the EPOS, shall maintain the schedules for planned outages suggested by the ESTPO Participants, unless those negatively affect the RS Indicators of the electricity system.

64. The ESO shall submit the draft EPOS each year by July 15 to the ESTPO Participants for review.
65. Upon receipt of the draft EPOS, the ESTPO Participants shall provide their suggestions and comments to the ESO by August 15.
66. The ESO shall summarize the suggestions and comments received from the ESTPO Participants by September 1 of the current year and publish the EPOS in the MMS, notifying the Commission and ESTPO Participants about it.
67. The ESO shall summarize and publish in the MMS the monthly and daily adjusted data of the EPOS in the following timeframes:
    1) By the 25th of every month for the following month;
    2) Each business day by 12:00 of the same day for the following second day, and if the following days are non-business days, for those days and the next following business day as well.

CHAPTER 12. DEMAND FORECAST

68. The ESO shall compile the EDEM based on the demand forecast data provided by the Universal Supplier, the Distributor, the Supplier, Utility-Scale Customers, Utility-Scale Plants (hereinafter, EDEM Participants), and the results of the ESO analysis.
69. The ESO shall compile the EDEM on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
70. The EDEM Participants shall submit their demand forecasts to the ESO by October 1 each year for the following year and shall submit the adjusted monthly and daily forecasts of the annual demand within the periods defined in Provision 60, sub-Provisions 1 and 2 of the ETN Code, respectively.
71. The annual demand forecast submitted by the EDEM Participants to the ESO shall include:
    1) The annual demand forecast of electricity by months (MWh);

2) The minimum and maximum active capacity demand by months (MW);
3) The minimum and maximum reactive capacity demand by months (MVAr);
4) The hourly load schedules for:
    a. Business days;
    b. Saturdays and Sundays;
    c. Public holidays and commemoration days.
5) Demand-side management measures, if envisaged.

72. Monthly demand forecasts submitted by the EDEM Participants to the ESO shall include:
    1) The monthly demand forecast of electricity by days (MWh);
    2) The minimum and maximum active capacity demand by days of the given month (MW);
    3) The minimum and maximum reactive capacity demand by days of the given month (MVAr);
    4) The adjusted hourly load schedules for the given month in the format provided in Provision 71, sub-Provision 4) of the ETN Code;
    5) The adjustments to demand-side management measures for the given month, if envisaged.

73. The daily demand forecast submitted by the EDEM Participants to the ESO shall include:
    1) The hourly distribution of daily electricity demand (MWh);
    2) The hourly distribution of daily reactive capacity demand (MVAr).

74. The EDEM Participants' forecasts of annual, monthly, and daily demand shall be submitted for all WEM connection points grouped by connection points to Transmission and Distribution Networks and take into account any anticipated changes during the planning period.

75. The demand forecast data of the EDEM Participants do not include the Utility-Scale Plants' own needs except for the cases when

electricity required for the own needs is planned to be purchased from the WEM.

76. The ESO shall compile the EDEM based on data mentioned in Provision 71 of the ETN Code, and, in case of monthly and daily adjustments, based on the data received from EDEM Participants according to Provisions 72 and 73 of the ETN Code respectively; it shall also consider the following:
    1) Expected GDP growth in the country;
    2) Potential impact of energy efficiency projects;
    3) Historical demand data;
    4) Forecast of Transmission Network losses;
    5) Possible impact of weather forecasts;
    6) Electricity forecasts for cross-border trade;
    7) Other information and factors that may have an impact on the EDEM.
77. The ESO shall compile the EDEM for the next year by November 1 of the given year, and the adjusted monthly and daily forecasts within the periods defined in Provision 67, sub-Provisions 1 and 2 of the ETN Code, respectively.

CHAPTER 13. GENERATION STRUCTURE FORECAST

78. The EGEN shall be compiled by the ESO based on the data provided by the Utility-Scale Plants and the results of the ESO analysis.
79. The ESO shall compile the EGEN on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this Chapter.
80. The Utility-Scale Plants shall provide to the ESO the hourly generation schedules forecasted for the following year for each generating unit by October 1 of each year, as well as:
    1) Each generating unit's maximum available capacity on a weekly basis;

2) Delivery of electricity at each Connection point with the Transmission or Distribution Network.

81. Utility-Scale Plants shall adjust and submit to the ESO the information provided in Provision 80 of the ETN Code within the periods specified in Provision 60, sub-Provisions 1 and 2 of the ETN Code, respectively.

82. The ESO shall compile the EGEN based on the data submitted by Utility-Scale Plants in accordance with Provision 80 of the ETN Code to meet internal market demand at minimum cost, considering the following as well:
    1) The need for efficient use of the installed capacities of the Generators and historical data of generation volumes;
    2) Power purchase guarantees given to Generators;
    3) Entry of new generation capacities into the Electricity system and retirement of current generation capacities;
    4) Possible impact of weather forecasts;
    5) Possible impact of energy efficiency projects;
    6) Electricity system Reliability and Security indicators;
    7) Other information and factors that may have an impact on the EGEN.

83. The ESO shall compile the EGEN for the next year by November 1 of the given year, and the adjusted monthly and daily forecasts within the periods specified in Provision 67, sub-Provisions 1 and 2 of the ETN Code.

84. The ESO, while developing the EGEN, may change the forecasted hourly schedules of the electricity generation of IPP plants in order to bring to a minimum the annual expenses for electricity purchase by the Universal Supplier, discussing this with the Universal Supplier and IPP Plants. The Universal Supplier and IPP Plants shall be obliged to follow the EGEN recommended by the ESO.

85. The ESO, while making monthly and daily adjustments of the EGEN, shall inform the Utility-Scale Plants of differences

in indicators if they differ from the indicators defined by the Commission for RPPs and IPPs in accordance with Provision 108 of the WEM Rules.

CHAPTER 14. TRANSMISSION NETWORK LOSS FORECAST

86. The ESO shall calculate the ELTRANS as the total sum of losses of Transmission Network facilities.
87. The ESO shall develop the ELTRANS on an annual basis and adjust it for monthly and daily periods in accordance with the procedure defined by this chapter.
88. The ESO shall calculate the ELTRANS based on the following:
    1) EDEM;
    2) EGEN;
    3) Forecasted cross-border electricity flows and electricity transits;
    4) Weather conditions;
    5) Transmission Network topology.
89. The ESO shall present in the ELTRANS the losses of the Transmission Network for the next year in an hourly manner and provide them to the Transmitter within the timeframes specified in Provision 90 of the ETN Code.
90. The ESO shall develop the ELTRANS for the next year by November 1 of the given year, and the monthly and daily adjustments within the periods specified in Provision 67, sub-Provisions 1 and 2 of the ETN Code, respectively.

CHAPTER 15. ELECTRICITY SYSTEM RELIABILITY AND SECURITY ASSESSMENT

91. The ESO shall assess the ERSL based on the data received from WEM Participants, as well as data stated in sub-accounts of the WEM Participants' e-cards involved in the MMS users' database

platform in accordance with Transactions and the results of the ESO analysis.

92. The ERSL shall include the following analysis, implemented in accordance with Annex 1 of the ETN Code:
    1) Operational reliability and security of the Transmission Network;
    2) Operational reliability and security of the facilities connected to the Transmission Network;
    3) Operational reliability and security of the interconnection lines with the neighboring electricity systems;
    4) Security of the electricity supply to end-use customers:
        a) Active and reactive power generation and consumption;
        b) Availability of sufficient capacity reserves in the electricity system;
    5) Static and Dynamic Stability of the electricity system.

93. The ESO shall assess the ERSL on an annual basis and adjust it for monthly and daily periods in accordance with the procedures defined in this Chapter.

94. For annual ERSL assessment, the ESO shall use the annual information on EPOS, EDEM, EGEN, and ELTRANS, as well as data on the import/export and transit of electricity provided by the EMO in accordance with Provision 99, sub-Provision 1 of the WEM Rules, taking into consideration the following:
    1) Historical operational data of the electricity system;
    2) Interconnection flows operational data;
    3) Operational events notifications and operational conditions that could impact electricity system reliability and security;
    4) Transmission Network constraints that may impact the demand and generation forecasts;
    5) Fuel supply options;
    6) Weather forecast data;
    7) Information on events that may affect the reliability and security of the electricity system.

95. The ERSL annual assessment shall be carried out every year by November 1 for the following calendar year. The ERSL shall be carried out for typical operational hours selected for analysis of the electricity system's reliability and security, defined by the ESO based on historical data and operational experience. The ERSL assessment shall contain, as a minimum, the following information:
   1) Total demand forecast for each month, week, day, and hour;
   2) Total available generation output for each month, week, day, and hour;
   3) Transmission Network losses;
   4) A description of any foreseeable situations, the occurrence of which may violate the RS Indicators;
   5) A description of any foreseeable situations, the occurrence of which may result in an inadequate active power reserve margin;
   6) The loss of load probability that represents the number of hours per year in relation to total hours when RS Indicators cannot be met using the available capacities, to determine additional capacity demand in the long term.

96. The ERSL monthly and daily adjustments shall be conducted taking into consideration the hourly data recorded on the Participants' virtual e-cards sub-accounts involved in the MMS users' database platform according to the WEM Transactions, as well as foreseeable changes in data applied by the ESO during the annual assessment within the following timeframes:
   1) By the 25th day of each month for the following month, by hour;
   2) By 12:00 of each day for the next second day, by hour;
   3) Each day for the following day, by hour, as follows:
      a) By 16:30, also considering the DAM results;
      b) By 19:30, also considering the Transaction Allocation of the WEM Participants, defined by Provision 171 of the WEM Rules.

97. The results of the annual ERSL assessment and its monthly and hourly adjustments shall be provided by the ESO to the Transmitter and BSP within the timeframes specified in Provisions 95 and 96 of the ETN Code, respectively. The daily results of the ERSL assessment shall be published by the ESO in the MMS as well, according to the timeframe defined in Provision 96, sub-Provision 3.b) of the ETN Code with notifications provided to the WEM Participants and the EMO.

SECTION 4. OPERATIONAL MANAGEMENT

CHAPTER 16. GENERAL PROVISIONS

98. Operational management aims to regulate actions of the ESO and the WEM Participants defined in this section to ensure reliable and secure operation of the electricity system.
99. The ESO and the following WEM Participants shall participate in the Operational management process (hereinafter, EOM Participants):
    1) Balancing Service Provider;
    2) Transmitter;
    3) Distributor;
    4) Utility-Scale Plants;
    5) Utility-Scale Customers.

CHAPTER 17. OPERATIONAL SUBORDINATION

100. In terms of operational subordination, all equipment and devices of the EOM Participants can be:
    1) Under Operational control and management of the ESO's dispatcher;
    2) Under Operational control of the ESO's dispatcher and under operational management of the staff on duty of the EOM Participant.
101. The ESO shall determine the list of equipment and devices of EOM Participants subject to transfer to its Operational control and management or Operational management, which transfer shall be formalized by December 1 of the given year based on the written consent that the EOM Participants provided to the ESO. If, based on the data submitted by the EOM Participant or following the ESO's own initiative, no changes are made to the list of equipment and devices agreed upon the previous year, then the

list shall remain in effect for the next year. Further changes to the equipment and devices stated in the list shall be made as needed based on data submitted by the EOM Participants or upon the ESO's initiative.

102. All actions regarding equipment and devices under Operational control and management of the ESO's dispatcher shall be performed by the on-duty personnel of the EOM Participant through the instruction issued by the ESO's dispatcher. Individual instruction shall be given for each action.
103. Actions regarding the equipment and devices that are under the operational control of the dispatcher of the ESO and under the management of the staff on duty of the EOM Participant shall be performed by the staff on duty of the EOM Participant with permission of the dispatcher of the ESO.
104. The staff on duty of the EOM Participant shall immediately inform the dispatcher of the ESO about any defects of equipment and devices that are under operational subordination of the ESO's dispatcher and unacceptable deviations from the Regime parameters.
105. The staff on duty of the EOM Participant that is subordinate to the ESO's dispatcher shall report to the dispatcher of the ESO after its shift as well as by request of the latter at any moment provide information about the existing scheme, as well as about the condition, Regime parameters, existing shortfalls, planned repairs, and switching of equipment and devices under operational subordination of the dispatcher of the ESO.
106. The staff on duty of the EOM Participants, in cases of absence from the workplace, can be replaced and the information about such replacement shall be submitted to the dispatcher of the ESO.
107. Each year before December 20, the EOM Participants shall exchange with the ESO the following information:

1) The approved list of the employees who are entitled to conduct the operational conversations;
2) The approved list of the operational personnel entitled to conduct operational conversations and carry out switching.

CHAPTER 18. OPERATIONAL COMMUNICATIONS

108. Operational communication between the ESO and EOM Participants shall be carried out to ensure reliable and secure operation of the electricity system.
109. Communication links used for operational communication shall be physically separated from other communication channels. Other communication channels may be used for operational communication when channels dedicated for this purpose are unavailable.
110. The EOM Participants shall install the Automated System for Technological Process Management (hereinafter, ASTPM) according to the requirements of "Technical rules for operation of facilities and networks" approved by the GoA Decision No. 1605N dated December 27, 2007. The minimum requirements for the data provided through the ASTPM shall be defined by the ESO.
111. According to the requirements of the "Technical rules for operation of facilities and networks" approved by the GoA Decision No. 1605N dated December 27, 2007, the ESO shall install an Automated System of Dispatch Control (hereinafter, SCADA).
112. The minimum requirements for the SCADA are set to:
    1) Ensure that the ESO receives data from the installation points of the SCADA and from the ASTPM of the EOM Participants;
    2) Ensure compliance with other Dispatch control devices of the ESO;

3) Be protected from unauthorized access.

113. The technical requirements for communication channels of the EOM Participants shall be set by the ESO.

114. The ESO shall ensure the stable and high-quality functioning of the communication channel and eliminate any defects or faults identified as soon as possible, with the support of the EOM Participants.

115. The EOM Participants' dispatch centers must be equipped with a dedicated dispatch communication switchboard for voice data exchange in real-time operations.

CHAPTER 19. PREVENTION AND ELIMINATION OF EMERGENCY STATES

116. The ESO shall develop instructions for the post-contingency restoration of the electricity system, thus defining the coordinated actions of the ESO and the EOM Participants in emergency events. The ESO shall approve the instructions for post-contingency restoration and each year by December 1 shall inform the EOM Participants of changes therein.

117. Based on the post-contingency restoration instructions, within one month, the EOM Participants shall develop their own internal restoration instructions.

118. The ESO shall coordinate the actions of the EOM Participants aimed at post-contingency restoration of the system. The EOM Participants shall participate in the restoration of the system after the contingency event following their own internal restoration instructions and instructions from the ESO.

119. The ESO, in cooperation with EOM Participants, shall analyze system emergency states that took place in the electricity system and develop prevention programs.

120. In case of emergency outages of facilities in the electricity system, the EOM Participant shall immediately notify the ESO.

121. The ESO shall inform the Transmitter as soon as possible of the emergency disconnection of the Transmitter's equipment under its operational control.

CHAPTER 20. READINESS TESTING OF IPP PLANTS

122. In the frame of operational management, the ESO shall implement readiness testing to check the readiness of generating units of IPP Plants if a capacity charge is defined in the Public-Private Partnership (PPP) contracts concluded with them.
123. The ESO shall conduct post-repair readiness testing of IPP generating units on a mandatory basis and as needed. Results of the readiness testing shall be recorded by the ESO in the Readiness Testing Act.
124. While conducting readiness testing of IPP generating units, the parties shall be guided by procedures for technical maintenance, renovation, and testing defined in the "Technical rules for operation of facilities and networks" approved by the GoA Decision No. 1605N dated December 27, 2007 as well as the values of equipment rating as prescribed by the manufacturers of equipment (minimum and maximum levels of the capacity, ramp rates, and others), considering the changes that result after dispatching.
125. If a planned readiness test has not been conducted by the ESO within the period from 00:00 of the first day until 24:00 of the last day of the calendar month (hereinafter, the Settlement month), then the capacity specified in the contracts defined in Provision 60 of the WEM Rules as "Contract capacity" for that period shall be considered as the ready capacity of the generating units of the Utility-Scale IPP Plants.
126. Should a failure occur in the electricity system and the generating unit of the Utility-Scale IPP Plant is disconnected from the electricity system while conducting readiness testing or such

testing could not proceed because, according to the opinion of the ESO, testing prevents recovery from the failure, then the testing shall be suspended by the instruction of the ESO and shall be considered not completed.

127. If the average capacity developed by a unit of the Utility-Scale IPP Plant during the readiness testing is 95 percent of the available quantity, the contractual quantity stated in Contracts defined in Provision 60 of the WEM Rules shall be approved by the Readiness Testing Act as the available capacity.

128. If, during the readiness testing:
   1) The generation capacity of the Utility-Scale IPP Plant generator cannot reach the Available capacity defined in Provision 127 of the ETN Code, or can reach it but cannot be kept at this level, then the average values recorded in the last hour for hydro units and the average value of the last 3 hours for the thermal units are set as the ready capacity in the Readiness Testing Act;
   2) The generator of the Utility-Scale IPP Plant is disconnected from the electricity system as an emergency, then 0 MW ready capacity is set in the Readiness Testing Act for the period until the next readiness testing.

129. If the Readiness Testing Act states a capacity lower than the Available capacity, then the Utility-Scale IPP Plant shall have a right to propose to the ESO additional readiness testing. The ESO shall conduct additional testing within 3 business days after receiving the application for such testing. Additional readiness testing shall be performed no more than once per Settlement month.

130. All Readiness Testing Acts shall be presented by the ESO to the EMO, the Universal Supplier, and the Utility-Scale IPP Plant before the first day of the month following the Settlement month.

CHAPTER 21. RELAY PROTECTION AND SYSTEM AUTOMATION

131. The elements of the electricity system (generators, transformers, transmission lines, reactors, capacitors, and others) shall be equipped with Relay Protection and System Automation (hereinafter, RPSA) devices, which are designed to respond to Emergency states of the system by disconnecting the failed element automatically by means of breakers.
132. Each year before November 1, the ESO shall submit to WEM Participants managing the RPSA the following:
    1) Pre-settings for the RPSA devices;
    2) Instructions to change the pre-settings of the RPSA devices;
    3) Instructions to ground the neutral windings of the transformers.
133. The WEM Participants managing the RPSA devices shall:
    1) Ensure the functioning of the RPSA devices;
    2) Ensure the maintenance of any RPSA devices located on their territory but owned by the ESO;
    3) Ensure the fulfillment of instructions received from the ESO on changing the pre-settings of the RPSA devices within the period specified by the ESO and providing immediate notification to the ESO in writing;
    4) Ensure unplanned inspection of RPSA devices at the request of the ESO.
134. Each year before October 15, the WEM Participants managing the RPSA devices shall submit for the ESO's approval the schedule of planned inspections for the next calendar year of the RPSA devices that are under the operational subordination of the ESO. The ESO shall review and, by November 1, submit its questions on these schedules to the WEM Participants managing the RPSA devices. The WEM Participants managing the RPSA devices shall submit their clarifications to the ESO questions by November 15

of the given year. The ESO shall summarize and, by December 1, approve the schedule of planned inspections of the RPSA devices for the next calendar year.

135. The WEM Participants shall carry out the planned inspections of the RPSA devices in accordance with the schedules approved by the ESO. If necessary, WEM Participants can carry out an unplanned inspection notifying the ESO about this at least 1 business day in advance.

136. The WEM Participants shall inform the ESO about the results of the planned and unplanned inspections of the RPSA devices completed during the given month by the 5th business day of the next month.

137. In case it is necessary to install new or replace the existing RPSA devices, the WEM Participants managing the RPSA devices shall submit an application to the ESO in writing.

138. Within 10 business days from receipt of the application defined in Provision 137 of the ETN Code, the ESO shall approve it or provide comments and recommendations. Within 10 business days from receipt of comments and recommendations, as a result of discussions held between the ESO and the WEM Participant, the ESO shall approve or reject the submitted application, stating the justifications for rejection.

139. The WEM Participants managing the RPSA devices shall immediately inform the ESO about failures of RPSA devices and eliminate malfunctions as soon as possible, informing the ESO.

CHAPTER 22. RELIABILITY OF ELECTRICITY SYSTEM OPERATION

140. The ESO shall take all actions defined by the ETN Code to maintain the RS Indicators.

141. The ESO shall provide access to EOM Participants about the

information on its servers regarding the states and operational schemes of the Electricity System.

142. The ESO shall publish on its official website the reliability requirements for the devices and equipment for the next calendar year as described in Provision 101 of the ETN Code and, before December 15, inform the EOM Participants. Those requirements shall serve as a basis for the EOM Participants to implement corresponding measures aimed at ensuring RS Indicators.
143. Before the 20th of each month following each quarter of the calendar year, the EOM Participants shall present actual reliability data on their respective devices and equipment described in Provision 101of the ETN Code to the ESO.
144. Each year before April 1, the ESO shall publish on its official internet site and inform the EOM Participants of the summary of the last year's actual reliability indicators for their respective Equipment and Devices specified in Provision 101 of the ETN Code, calculated according to RS Indicators.
145. The reliability indicator for electricity supply (delivery) at each Connection point of the electricity system shall be established in the Connection Contract and be specified, regardless of any limitations and their causes, as a ratio between the sum of annual hours delivering electricity at the given Connection point and the total hours per year and must be not less than 0.99. In case of deviation of the contract reliability indicator for supply (delivery) of electricity at the given Connection point of the electricity system, the responsibility to the connected person (including compensation for possible damages caused by the deviation) shall be borne by the Transmitter or Distributor depending on the Connection point. If unlawful actions (or inaction) of a third party are the immediate cause of such deviation, then the third party shall be proportionally responsible to the Transmitter and Distributor, depending on the Connection point, and the latter shall acquire a recourse right to the third party for the incurred amount.

146. The EOM Participants shall submit to the ESO a report on the actual level of reliability of the equipment and devices under the latter's operational control, within the terms and conditions specified by the ESO. After receiving the report, the ESO shall analyze the rules of the ETN Code and submit the results to the Commission by the last day of the month following each quarter.

SECTION 5. DISPATCH IN REAL TIME

CHAPTER 23. GENERAL PROVISIONS

147. The Dispatch shall be conducted by the ESO to ensure the reliable and secure operation of the electricity system in real time.
148. During the Dispatch, the ESO shall:
    1) Monitor the real-time cross-border and internal electricity flows;
    2) Control the operational functioning of equipment and devices under its operative subordination;
    3) Issue Dispatch instructions to the EOM Participants as appropriate to provide System services in cases defined in the ETN Code;
    4) Determine the availability of the necessary reserves at the BSP and activate these reserves by issuing Dispatch instructions;
    5) Prevent or eliminate congestion in the Transmission Network;
    6) Take all necessary actions to maintain an appropriate level of reliability and electricity quality, taking into account the requirements of the RS Indicators and technical regulations;
    7) Take all necessary actions to counteract Emergency Situations, as it is foreseen in the ETN Code and the WEM Rules.
149. In cases and procedures specified in the ETN Code, to ensure the RS Indicators in the process of dispatching, WEM Participants shall provide System services, which are classified as follows:
    1) Balancing and frequency control;
    2) Reactive power and voltage control;
    3) Electricity system black start in case of full system shutdown.
150. The ESO and the EOM Participants shall participate in the process of Dispatching.
151. The ESO shall involve the EOM Participants in the process of Dispatching in the following cases:

1) In order to provide Balancing and frequency control type of System service:
   a) The BSP, in terms of its Primary, Secondary, and Tertiary Reserve, and the Utility-Scale Plants, in terms of their Primary Reserve, shall be subject to Dispatch in Normal and Emergency States;
   b) All EOM Participants may be subject to Dispatch in Emergency Situation.
2) In order to provide the Reactive power and voltage control type of System service, all EOM Participants shall be subject to Dispatch;
3) In order to provide the Black start in case of full system shutdown type of System service, the Utility-Scale Plants involved in the list of Black Start Facilities specified in Provision 180 of the ETN Code are subject to Dispatch during the Emergency state.

152. The WEM Participants shall take all necessary measures to comply in real time with their Transactions and Transaction Allocation scheme, unless otherwise specified in this section of the ETN Code for the WEM Participants.
153. The ESO may change the Transaction Allocation of the BSP in order to ensure the RS Indicators.
154. During the Dispatch, to ensure the reliable and safe operation of the electricity system in real time, the ESO shall perform congestion management in the Transmission Network in accordance with the requirements of Chapter 28 of the ETN Code.
155. The ESO and WEM Participants shall be guided by the requirements of Chapter 29 of the ETN Code in situations requiring unavoidable limitations of electricity supply .

CHAPTER 24. REQUIREMENTS TO DISPATCH INSTRUCTIONS

156. The ESO shall carry out the Dispatch by issuing dispatch instructions to the EOM Participants in cases provided for by Provision 151 of the ETN Code.

157. While issuing dispatch instructions, the ESO shall take into consideration the following factors:
    1) Difference between forecasted and actual electricity demand;
    2) Difference between the planned and actual schedules of cross-border active power interchanges;
    3) Availability of reserves for balancing purposes;
    4) Technical restrictions per generating unit;
    5) Changes in the Transmission Network configuration;
    6) Changes in the Distribution Network affecting the quality indicators of electricity at Boundary Points of the Transmission and Distribution Networks;
    7) Availability of the respective types of generating capacity reserves that guarantee the reliability and quality of electricity supply to customers during parallel operation, and potential risks of electricity supply interruption;
    8) The need to change the voltage schedules of power plant buses connected to the Transmission Network, or of the Transmission Network substation buses, to secure the required reserve of reactive power;
    9) Changes in the generation schedules of generating units;
    10) Changes in the schedules of generating units operating in a combined heat and electricity generation cycle;
    11) Changes in the schedules of generating units using renewable resources for generation of electricity;
    12) Occurrence of disturbances during electricity system operation;
    13) Reliable and secure operation of the electricity system.

158. Depending on the implementation mode, the Dispatch instructions may be fulfilled:
   1) By applying system automation;
   2) By applying dispatch instructions issued by dispatcher.
159. Depending on the control type, the Dispatch instructions may be:
   1) Direct – using remote control facilities, both automatic and/or manual;
   2) Indirect – through the shift operators at the remote end of the control loop.
160. Depending on the communication type, the Dispatch instructions may be:
   1) Electronic – using IT facilities for data exchange and communication;
   2) Verbal – using the telephone.
161. The dispatch instruction shall define the action subject to implementation and the period. Dispatch instructions shall be formulated clearly to minimize the probability of misunderstanding and errors, in accordance with the list of dispatching abbreviations and notions approved by the Central Dispatch Service of the ESO. In case of introducing changes in the list of abbreviations and notions, the ESO shall inform the EOM Participants of that fact each year before December 1.
162. Once an instruction from the dispatcher of the ESO is received, the person on duty at the EOM Participant shall repeat it and receive confirmation. Each instruction given by the Dispatcher of the ESO to the person on duty at the EOM Participant and information about the fulfillment of such instructions shall be registered in the operational logbooks of the ESO dispatcher and the person on duty at the given EOM Participant. The person on duty shall immediately and strictly follow the Dispatch instruction and start carrying it out from the moment it is confirmed by the dispatcher of the ESO.

163. If the staff on duty at the EOM Participant considers the Dispatch instruction to be inconsistent with the requirements of the ETN Code, then it should immediately inform the dispatcher of the ESO and provide justifications. If the Dispatch instruction issued by the dispatcher of the ESO is confirmed, the staff on duty shall follow the instruction, making an appropriate record in the operational logbook. If fulfilling the Dispatch instruction issued by the dispatcher of the ESO is found to be impossible, the EOM Participant shall immediately inform the dispatcher of the ESO.

164. The ESO shall ensure that all Dispatch (operational) communications between him/her and the EOM Participants be automatically registered and archived using electronic devices. Archived Dispatch instructions shall be preserved for at least 3 years. The information may be provided to the EOM Participants based on their written request to the ESO within 7 days after receiving the request.

165. Upon the loss of communications and the impossibility of issuing and/or receiving Dispatch instructions:
    1) EOM Participants shall undertake the actions required for restoration of communications;
    2) Generating units shall follow active and reactive power and voltage values stated on the last available schedules;
    3) EOM Participants shall organize new communication routes and shall mutually inform each other.

CHAPTER 25. BALANCING AND FREQUENCY CONTROL IN REAL TIME

166. For Balancing of supply and demand and Frequency control in the electricity system in real time, in cases specified in the ETN Code, the ESO shall use the Primary, Secondary, and Tertiary Reserves of the BSP and Utility-Scale Plants.

167. The requirements for the Primary, Secondary, and Tertiary

Reserves of the BSP and Utility-Scale Plants shall be set based on the RS Indicators, considering the technical parameters of the electric facilities of the latter. The ESO shall define the size of the reserves for the BSP and Utility-Scale Plants each year for the next year and shall inform the relevant participants by December 1.

168. For Balancing and Frequency control purposes, the ESO shall use the Primary Reserves of the BSP and Utility-Scale Plants while they operate synchronously with the electricity system. The Secondary and Tertiary Reserves in the electricity system shall be provided by the BSP and used as necessary following the Dispatch instructions of the ESO.

169. For Balancing and Frequency control purposes, the dispatcher of the ESO shall have the right to issue the following Dispatch instructions to the BSP:
    1) Instruction to start up, synchronize, or shut down the unit;
    2) Instruction to ensure active and/or reactive capacity set points;
    3) Other instructions on activities of the BSP to maintain the reliability and security of the electricity system.

170. The dispatcher of the ESO shall have the right to issue the following instructions to the EOM Participants regarding the equipment or devices under its operative subordination:
    1) Instruction to switch on, switch off, put under voltage;
    2) Instruction to organize an unplanned check of overhead lines;
    3) Instruction to check the equipment and devices.

171. In the event that the reliability and security of the electricity system is violated or is at the risk of violation, or in cases requiring unavoidable limitations of electricity supply, or in force majeure situations, the ESO shall declare an Emergency Situation. In Emergency Situation, for balancing and frequency control purposes, the ESO shall have the right to give Dispatcher instructions to the other EOM Participants, as specified in Provision 169 of the ETN Code.

172. The ESO shall, as soon as possible, inform the WEM Participants through the MMS about the start and end of the Emergency Situation.

CHAPTER 26. REACTIVE POWER AND VOLTAGE CONTROL IN REAL TIME

173. To provide Reactive power and voltage control type of System service in the electricity system, the ESO shall use:
    1) The generating capacities under control of the BSP;
    2) The generating units of Utility-Scale Plants;
    3) The Transmitter's voltage control equipment and devices;
    4) The Distributor's voltage control devices connected to the Transmission Network;
    5) Utility-Scale Customers voltage control devices connected to the Transmission Network.
174. The tolerable deviations from nominal voltages and their durations in the Transmission Network nodes for different voltage levels are defined in accordance with the RS Indicators.
175. To provide Reactive power and voltage control type of System service at the Transmission Network, the ESO may issue the following Dispatch instructions to the Transmitter:
    1) Switching in/out of shunt reactors and capacitor banks directly connected to the Transmission Network.;
    2) Switching in/out of transmission lines;
    3) Altering the tap positions of on-load transformer changer (OLTC) devices of transformers and auto- transformers;
    4) Changing the mode of operation and voltage set point of synchronous and static var compensators.
176. To enable Reactive power and voltage control in the electricity system, the ESO will issue the following Dispatch instructions to the EOM Participants (except for the Transmitter):
    1) Instruction to ensure the voltage setpoint;

2) Instruction to ensure the reactive power setpoint;
3) Instruction to increase or decrease the reactive power.

177. EOM Participants shall provide Reactive power and voltage control type of System service in the Normal State of operation as long as the provision of the service does not require changing the generating unit active power. In the case of an Emergency Situation, the reactive power and voltage control System service shall be provided by the EOM Participants, despite the changes in active power, based on the Dispatch instructions of the ESO.

CHAPTER 27. ELECTRICITY SYSTEM BLACK START

178. For restoration of the Normal State in the electricity system after full blackout, the ESO shall involve the generating units of the Utility-Scale Plants (hereinafter, the Black Start Facility) that have the capability to start up and synchronize with the electricity system without the need for external electricity supplies.
179. Once a year, by October 1, the Utility-Scale Plants shall provide to the ESO their list of Black Start Facilities by generating unit.
180. The ESO shall examine the list of Black Start Facilities of the Utility-Scale Plants, approve it by November 1 and notify the Commission and the Utility-Scale Plants managing the Black Start Facilities. In the process of examining the list of Black Start Facilities of the Utility-Scale Plants, the ESO shall have the right to request additional information or to start these facilities in order to find out their ability to start up and synchronize after a full blackout of the electricity system without external voltage supply.

CHAPTER 28. CONGESTION MANAGEMENT

181. In the process of real-time operation of the electricity system, the ESO shall control the actual loading of the Electricity system

elements, including cross-border interconnection transmission lines.

182. Once the Electricity System congestion is identified, the ESO shall undertake all necessary measures to solve the congestion.

183. For congestion management in the Electricity system, the ESO may issue Dispatch instructions to the EOM Participants regarding the change of the Normal state configuration.

CHAPTER 29. UNAVOIDABLE LIMITATIONS OF ELECTRICITY SUPPLY

184. To prevent a frequency drop, which is the result of a change in the balance of active power, or to restore frequency levels, unavoidable limitations of the supply of WEM Participants (hereinafter, limitations of electricity supply) shall be implemented by using Automated frequency load shedding and Dispatch load shedding programs.

185. Principles of operation and pre-settings for Automated frequency load shedding and automated recloser devices shall be defined by the ESO based on the RS Indicators.

186. Limitations of electricity supply of the WEM Participants shall be implemented by the Automated and Dispatch load shedding programs that are compiled by the initiative of the ESO based on the RS Indicators. After receiving the programs, the EOM Participants shall approve them and inform the ESO of the fact within 5 business days.

187. Automated and Dispatch load shedding programs shall be compiled considering the following obligatory requirements:
    1) Limitations of electricity supply up to the fixed technological and/or emergency capacity level fixed in the WEM contract;
    2) Limitations of electricity supply applied in accordance with the priorities set out in Article 49 of the Law based on the list of customers approved by the Government of the RoA;

3) Limitations of electricity supply applied to all other WEM Participants.

188. If a WEM Participant connected to the Transmission Network is included in the Automated load shedding program, then the records regarding the order of priority for this participant shall be stated in the Acceptance of the WEM Contract.

189. The limitations of electricity supply of WEM Participants shall be eliminated in the following order:
   1) The WEM Participants as described in Provision 187, sub-Provisions 1 and 2 of the ETN Code;
   2) All other WEM Participants.

190. The duration of the continuous limitation of the electricity supply shall not exceed four hours.

191. The decision on the application of electricity supply limitation programs shall be made by the ESO. In such situations, the ESO can perform disconnections, informing the WEM Participants as soon as possible.

192. The Distributor, based on the instruction of the ESO, shall be obliged to limit the electricity supply of the customers connected to the Distribution Network.

193. The decision on the application of electricity supply limitation programs for customers connected to the Distribution Network shall be made by the Distributor, providing the ESO with information about the volumes of such limitations. Limitations of electricity supply shall be eliminated once agreed with the ESO.

194. During the application of limitations programs, the relationships between the ESO and the Distributor are defined by the EDN Code.

SECTION 6. CONNECTION OF NEW OR RECONSTRUCTED CAPACITIES TO THE TRANSMISSION NETWORK

CHAPTER 30. GENERAL PROVISIONS

195. The connection process regulation of new or reconstructed capacities aims to ensure non-discriminatory access to the Transmission Network.
196. The following WEM Participants (hereinafter, the Applicant) may connect to the Transmission Network:
    1) Generators;
    2) Distributor;
    3) Qualified Customers (except for the Residential);
    4) Entity intending to obtain a Qualified Customer status (except for the Residential).
197. An Applicant aiming to be connected to the Transmission Network shall:
    1) Apply to receive a Connection Reference, if intends to receive an electricity generation license;
    2) Apply for development of Technical Conditions;
    3) Sign a Connection Contract;
    4) Receive a Connection Permit.
198. It is not permitted to demand that the Applicant make payments, provide compensation, submit information and documents, or burden them with obligations, unless they are defined by the ETN Code or other normative legal acts.

CHAPTER 31. RECEIPT OF CONNECTION REFERENCE

199. In order to receive a Connection Reference, the Applicant shall apply to the Transmitter, providing information on the facility name, location (address), connection or added intended capacity,

and the voltage of the connection point, attaching a document certifying payment of the service fee defined in Provision 200 of the ETN Code.

200. In order to receive the Connection Reference, the Applicant shall pay a service fee to the Transmitter equal to 500,000 AMD (including VAT); of that amount, 250,000 AMD (including VAT) is transferred by the Transmitter to the ESO within 15 business days after receiving the amount.

201. Within 15 business days of the Applicant's application, the Transmitter shall check the application for compliance with the requirements set out in this chapter, and, if necessary, shall make corresponding adjustments together with the Applicant, and:
   1) in case of compliance with Provision 199 of the ETN Code, shall:
      a) Develop the draft of the Connection Reference;
      b) Submit the application and the draft of the Connection Reference to the ESO;
      c) Transfer 250,000 AMD (including VAT) to the ESO and submit the document certifying the payment.
   2) In case of non-compliance with Provision 199, shall return the application.

202. The payment mentioned in Provision 200 of the ETN Code is subject to return only if the application is rejected in accordance with Provision 201 of the ETN Code.

203. The Connection Reference shall be developed considering the requirements of the technical regulations of the RoA to complete the works, ensuring the reliability level of the electricity supply of the Applicant with minimal costs.

204. The Connection Reference shall include at least:
   1) Name, Surname of the Applicant;
   2) Name, type, capacity, and location of the plant (region, community, settlement);
   3) Connection point to the Transmission Network, the

required voltage level, and the length of the planned transmission line;

4) Reasoned measures for strengthening the existing electrical network that meet the conditions of the new connection (increase in the cross-sectional area of the wires, replacement of power transformers, installation of additional cells, etc.);
5) Term of the Connection Reference.

205. The term of the Connection Reference shall be 6 months, starting from the moment that notification is presented in the appropriate manner.
206. The term of the Connection Reference can be extended only once. To extend the term, the Applicant shall submit an application to the Transmitter not earlier than 5 business days prior to the expiration of the term, paying 250,000 AMD (including VAT). In this case, the Transmitter shall extend the term for another 6 months. The application submitted later than set in this Provision shall be subject to rejection. Within five days, the Transmitter shall inform the ESO of all applications and rejections.
207. Within 20 business days of receiving the information submitted by the Transmitter, the ESO shall study the impact of the Connection Capacity on the RS Indicators, assess the draft Connection Reference together with the Transmitter from the perspective of integrity and the necessity of measures aimed at implementation of necessary changes in Connection Capacity and Transmission Network, and present to the Transmitter the agreed draft of the Connection Reference.
208. The Transmitter shall issue a Connection Reference within 40 business days from receiving from the Applicant the complete information (documents) prescribed in Provision 199 of the ETN Code
209. During the whole term of the Connection Reference, the capacity mentioned in the Connection Reference at the Connection Point fixed there shall be considered to be reserved for the Applicant.

If an electricity generation license is being issued, the capacity of a power plant in the Transmission Network at the Connection Point fixed in the Connection Reference shall be considered to be reserved until the issuance of Technical Conditions.

210. In order to receive a new Connection Reference in case of the expiration of its term, the Applicant shall have the right to apply to the Transmitter for a second time in accordance with the procedure envisaged by the ETN Code.

211. If an electricity generation license is being issued during the effective term of the Connection Reference, Technical Conditions shall be issued to the Applicant in accordance with the Connection Reference if nothing else is agreed between the parties.

CHAPTER 32. DEVELOPMENT OF TECHNICAL CONDITIONS

212. In order to develop the Technical Conditions, the Applicant shall submit the application to the Transmitter in accordance with Annex 3 of the ETN Code and attach the following:
    1) Documents certifying (proving) his/her rights in respect to the area of Connection Capacity;
    2) A document certifying payment to the Transmitter for providing the Technical Conditions.

213. In order to receive the Technical Conditions, the Applicant shall pay a service fee to the Transmitter equal to 500,000 AMD (including VAT), except for the case when the Applicant has reserved capacity prescribed in Provision 209 of the ETN Code. In such cases, to receive the Technical Conditions, the Applicant shall pay a service fee to the Transmitter equal to 50,000 AMD (including VAT).

214. Within 15 business days of the Applicant's application, the Transmitter shall check the application for compliance with the requirements set out in this chapter and, if necessary, make corresponding adjustments together with the Applicant, and

1) In case of compliance with Provision 212 of the ETN Code, shall:
    a) Develop the draft of the Technical Conditions based on the requirements of the technical regulations, and in case the Applicant has the effective Connection Reference, based on the Connection Reference as well;
    b) Submit the application and the draft of the Technical Conditions to the ESO;
    c) Transfer 250,000 AMD (including VAT) to the ESO and submit the document certifying the payment, except for the case when the Applicant has reserved capacity prescribed in Provision 209 of the ETN Code.
2) In case of non-compliance with Provision 212 of the ETN Code, shall return the application.

215. Within 15 business days of receiving the information submitted by the Transmitter, the ESO shall study the impact of the Connection Capacity on the RS Indicators, assess the draft Technical Conditions together with the Transmitter from the perspective of integrity and the necessity of measures aimed at implementing necessary changes in Connection Capacity and Transmission Network, and present to the Transmitter the agreed Technical Conditions.

CHAPTER 33. CONNECTION FEE

216. The Connection Fee shall be calculated and the amount shall be determined by the Transmitter based on the agreed Technical Conditions in order to compensate expenses necessary for ensuring the connection of the Connection Capacity to the Transmission Network.

217. The Connection Fee shall be calculated within 15 business days after receipt of the agreed Technical Conditions in accordance with Provision 215 of the ETN Code. The amount of the Connection

Fee shall be determined based on expenses for similar designs and is subject to adjustment in the design stage.

218. The Connection Fee for connection of the Connection Capacity to the Transmission Network shall include the sum of expenses required for construction of new capacities, reconstruction of existing capacities, purchase and installation of the metering device as well as the equipment and software required for the connection to the DAS, and other services that are deemed necessary for connection purposes as described in the ETN Code and technical regulations, including expenses for design.

CHAPTER 34. CONNECTION CONTRACT

219. Within 10 business days after calculation of the Connection Fee, the Transmitter shall provide the Applicant with the solely signed (verified) draft of Connection Contract attaching the Technical Conditions agreed with the ESO and calculation of the Connection Fee, which are considered to be an integral part of the Connection Contract.
220. The Applicant shall sign (verify) the solely signed (verified) Connection Contract and return it to the Transmitter within 6 months after receipt. A contract presented later than this has no legal force.
221. Within 5 business days after receiving the signed (verified) copy of the Connection Contract from the Applicant, the Transmitter shall inform the ESO.
222. The Connection Contract shall include the following:
    1) Deadline for submission of the examined connection design to the Transmitter for approval;
    2) Deadline for approval of the connection design presented for the Transmitter's approval by the ESO and EMO;
    3) Estimated amount of the Connection Fee and schedule for payments (timeline), as well as the mechanisms for adjusting

the initial and final amounts of the Connection Fee;

4) Date for connecting the capacity to the Transmission Network and responsibilities of participants in case of a breach of the terms.

223. Any change in the Connection Contract agreed between the parties shall be done according to the procedures and deadlines prescribed in the Connection Contract (if otherwise is not specified by the Connection Contract).

224. Within the scope of the Connection Contract, the reconstructed as well as newly constructed capacities in the Transmission Network shall be considered the property of the Transmitter, while the metering device as well as other equipment and software necessary to connect to the DAS shall be the property of the Applicant.

225. Control over fulfillment of the Contract shall be performed solely by the contracting parties.

CHAPTER 35. CONNECTION PERMISSION

226. To obtain Connection Permission, the Applicant shall submit the following documents to the Transmitter at least 40 business days in advance of the connection date mentioned in the Connection Contract:
    1) A copy of the construction completion document as it is provided for by the legislation of the RoA;
    2) A copy of the conclusion (permission) of the assessment made on the given capacity issued by the state body authorized to implement technical inspections;
    3) Application required as described in Annex 4 of the ETN Code;
    4) Plan of actions for connection.

227. The Transmitter, within 10 business days, shall check the compliance of the information submitted by the Applicant

according to the requirements set in Provision 226 of the ETN Code and shall submit the plan of action for connection to the ESO for agreement.

228. Upon receiving all necessary information from the Transmitter, the ESO shall agree with the plan of actions for connection within 10 business days.
229. After receiving the ESO's agreement, the Transmitter shall issue the Connection Permission to the Applicant (in case the conclusion is positive) or inform them of any non-compliance identified (in case the conclusion is negative) within 10 business days. If an identified non-compliance is not eliminated by the Applicant within 10 business days, the connection permission shall not be issued, and the connection date mentioned in the Connection Contract shall be extended according to the number of days of the delay.
230. Within 5 business days after receiving the Connection Permission, the Applicant shall inform the Transmitter and the ESO in writing about the preferred date for the actual connection of the Connecting Capacity to the grid.
231. If, in the ESO's opinion, the preferred date for the actual connection (launching or testing) mentioned by the Applicant is not acceptable in terms of ensuring the reliability and security of the operation of the electricity system, then within 3 business days, the ESO shall negotiate with the Applicant to change the connection date (launching or testing).
232. Connecting the Connection Capacity to the Transmission Network shall be carried out as per the plan of action for connection mentioned in Provision 228 of the ETN Code.
233. The Applicant shall test its Connection Capacity connected to the Transmission Network in order to confirm the compliance of that Connected Capacity with the terms mentioned in the Connection Contract. Such testing shall be performed in accordance with the plan of action agreed with the ESO.

SECTION 7. ELECTRICITY METERING REQUIREMENTS

CHAPTER 36. GENERAL PROVISION

234. The requirements for electricity metering in the WEM are intended to ensure the integrity, continuity, transparency, and uniformity of the Commercial Metering.
235. Electricity metering in the WEM shall be implemented by the EMO through the DAS and the Distributor's automated system of electricity metering.
236. The Metering Point of the WEM Participant shall be equipped with a Metering Complex and registered by the EMO in the DAS. The Metering Complex shall ensure:
    1) Metering of active and reactive components of electricity;
    2) The compliance of the accuracy class of the elements of the Metering Complexes with the requirements of Chapter 38 of the ETN Code;
    3) The transfer of metered data in electronic form to the metering database.
237. Expenses related to the acquisition, installation, replacement, maintenance, repair, inspection, and verification of the Metering Complex and other components of the DAS under the management of the WEM Participant, as well as the responsibility for maintaining the integrity of the Metering Complex are borne by the possessor.
238. The EMO shall carry out Commercial metering at all Boundary points of the WEM Participants as well as at Import and Export points. Metering shall be conducted in such a manner to ensure:
    1) Determination of the amount of electricity generated by the Generators, and for Utility-Scale Plants differentiated by each Generator, the amount of electricity for own needs, and the amount of electricity supplied;

2) Determination of the amounts of electricity transferred or transited via the Transmission Network;
3) Determination of the amount of electricity supplied to the Distribution Network as well as the amounts of energy supplied from the Distributor's network to the network of the Transmitter and to Generators;
4) Determination of the amount of electricity delivered to the WEM Participants;
5) Determination of the amounts of electricity imported and exported.

239. The WEM Participants shall not interfere with the functioning of any element of their Metering Complexes, any metering data recorded, or the hourly reading of the electricity meter.

CHAPTER 37. GENERAL CHARACTERISTIC OF THE DAS

240. The DAS shall include the following:
1) Metering Complexes;
2) Primary data collecting server (communication server);
3) Data processing and settlement server (main server);
4) Nodal servers (data collection and transferring servers) or converters and devices for direct reading of meters by fiber optic cable or mobile connection, which are installed at substations and generating plants;
5) Plant and substation servers, which are located at the control centers of Generators (including HPP cascades) and the Transmitter;
6) Portable computers, which are used to import data to the database in cases where communication is disrupted or if the facility where the Metering Complex is installed has no telecommunication device;
7) Database for nodal and regional level servers;
8) Telecommunication infrastructure, including communication

channels, local and large-scale computer networks, modems, converters, commutators, switches, managing and supporting software packages, etc.

241. The DAS shall ensure:

1) Electronic data transfer to the settlement database;
2) Registration of data received from Metering Complexes and its proper protection;
3) Registration and availability of information in the data collection and transmission device (hereinafter DCTD) database regarding Generators, Transmitter, Distributor, and Qualified Customers;
4) The amount of electricity recorded at each WEM Metering point and calculated per Boundary point.

242. Requirements for the servers and parameters of computers as well as software involved in the DAS shall be set by the EMO and published on its official website.

243. Commercial and control meters of the electricity involved in the DAS shall comply with the requirements set in the RoA for static meters for Commercial metering with IEC11070P (optical port) and RS485 interface, which are included in the list of the EMO software-supported devices and are published on the official website of the EMO.

244. The metering database shall include the following information:

1) Recording of active and reactive energy and power passed through the Metering point counted as integral at 30-minute metering intervals, as well as the value of the power coefficient during the mentioned interval;
2) Information about any changes made to the database and the person who made them;
3) Information about each element of the electricity Metering Complex (voltage and current transformers, technical parameters of the meters, calibration data, manufacturing number, etc.).

245. In case of replacement of the Metering Complex, all newly installed meter data shall be entered into the database by the EMO.
246. The DAS shall be managed by the DAS Chief Administrator through the DAS Administrators.
247. The EMO shall ensure the availability of the DAS for each DAS Administrator per their applicability and shall inform each DAS administrator about the changes in software packages, technical-security requirements, or data related to the latter no later than 2 business days after making them.
248. The DAS Chief Administrator may reprogram the electricity meter if a software error is detected as a result of a self-diagnosis.
249. The DAS Chief Administrator may establish balance settlement groups in the DCTD in accordance with the settlement groups set up on the main server.
250. The EMO and WEM Participants shall be responsible for maintaining the confidentiality of passwords used in the DAS.
251. The DAS Chief Administrators and DAS Administrators shall be required to archive the database of the main regional servers under their responsibility at least once every 3 months.

CHAPTER 38. REQUIREMENTS FOR METERING COMPLEXES

252. A WEM Participant's Metering Complex shall be installed at the Boundary point; in cases when it is sufficiently justified and approved by the EMO, it can be installed beyond the Boundary point, such that the electricity technological losses occurring at the facilities located between the point of installation of the Metering Complex and the Boundary point are negligible for the contracting parties.
253. The WEM Participants, based on their actual electrical connections and Boundary points, shall decide on the location of electricity commercial and control Metering Complexes, to be agreed with the EMO.

254. The Metering Complexes shall be installed so as to:
   1) Form an electricity commercial settlement based on meter readings, without applying calculated losses of electricity;
   2) Minimize mechanical damage as well as unacceptable environmental impact;
   3) Minimize unauthorized interference to the connection scheme and the work of Metering Complexes;
   4) Make both commercial and control meter readings visible to the representatives of the contract parties and to the representative of the EMO;
   5) Properly maintain the Metering Complex;
   6) Ensure the safety of people's life and health.

255. The functions related to the installation, replacement, maintenance, performance testing, and calibration of the Metering Complexes shall be coordinated by the EMO.

256. The calibration of the metering device or its individual elements shall be conducted by the company responsible for implementing metrological control in accordance with the legislation of the RoA (hereinafter, Metrological Body), using the means of the managing company.

257. The installation and replacement of Metering Complexes or their individual elements shall be implemented with the participation of the managing company of the Metering Complex, Transmitter, or Distributor respectively (depending on which network is connected to the given WEM Participant) and the EMO by compiling a tripartite act in accordance with Annex 5 of the ETN Code. In this case, the managing company shall ensure that alternative equivalent metering data are transferred to the EMO.

258. The terminal clamps, metering transformers, or doors of their electrical panels or of cabinets shall be sealed and seals removed by the EMO in participation with the managing company of the given Metering Complex and the Transmitter or Distributor respectively (depending on which network the given WEM

Participant is connected to) by compiling a tripartite protocol in accordance with Annex 6 of the ETN Code. To eliminate any emergency that occurs in the Metering Complex, the seals can be removed by the managing company of the Metering Complex, immediately informing the EMO and the other party about this. In such cases, the reseal of the Metering Complex shall be carried out as prescribed in this provision within 72 hours.

259. The requirements for the Metering Complexes, parameters of their individual elements, accuracy and accuracy testing of the meters and measuring transformers, and secondary circuits of the facilities shall comply with the technical regulations effective in the RoA, particularly:
    1) Secondary circuits of the electrical facilities - management, signal, control, automation and relay protection circuits, and measuring transformers shall operate jointly with the electrical circuits in accordance with the requirements of the technical regulation "Requirements for electrical facilities protection and automation device" adopted as the GoA decision No. 42-N dated January 17, 2008.
    2) The commercial and control meters shall be installed in accordance with the requirements of the technical regulation "Technical requirements to the electrical equipment of the special facilities" adopted as the GoA decision No. 75-N dated January 15, 2009.
    3) The measurements of the electrical parameters and accuracy classes of the measuring devices shall comply with the requirements of the technical regulation "Requirement to the devices of the electrical facilities" adopted as the GoA decision No. 1943-N dated December 21, 2006.
    4) The static meters for watt-hours of the active energy of the alternative current shall meet the technical requirements established by the Ministry of Energy Order No. 96-ZD dated June 22, 1999 "On approval of technical requirements to

the static meters for watt-hours of the active energy of the alternating current of 50Hz allowed to use in the electricity metering system of the Republic of Armenia."

CHAPTER 39. METERING DATA COLLECTION AND PERIODICITY

260. Metering data collection shall be implemented by the EMO through the DAS and the Distributor's automated system for electricity metering.
261. The Distributor shall ensure EMO access to the data of WEM Participants from the Distributor's automated system of electricity metering, in accordance with the EDN Code.
262. In order to collect the metering data of the DAS, the EMO shall ensure the workable state of the system-level server, the main server, and DCTD software packages and ensure data collection from DCTD to the system-level server.
263. The DAS (meters and servers) clocks shall be periodically checked so that they are synchronized with the effective time in the RoA.
264. The WEM Participant shall ensure that the DCTD collects of data registered in the meters of the Metering Complexes that they manage.
265. The EMO shall ensure Metering data collection through the DAS for every Settlement Period of the Trading Day as of 24:00.
266. In the middle and at the end of a calendar month, the EMO shall compile the actual hourly balance of the electricity system by Boundary points and Metering points within 6 calendar days.
267. For the development of the actual hourly balance of electricity, agreed metering settlement groups between the WEM Participants shall serve as a basis; these groups shall be repeated without changes in the system and regional servers. Any change in these settlement groups shall be carried out only with the agreement of the parties.

CHAPTER 40. CHECKING METERING COMPLEXES AND ELECTRICITY RECONCILIATION

268. For metering data verification, the EMO shall:
   1) Conduct a visual inspection of the Metering Complex at least once during the calendar year to check the integrity of the Metering Complex and availability of seals with the participation of the managing company of the Metering Complex and the Transmitter or Distributor respectively (to which network the given WEM Participant is connected);
   2) Compile balance groups from the meters involved in the Metering Complexes and consider the electricity balance formed in these groups at least once during the month. In case the electricity balance deviation in the balance group exceeds the limit values of the average statistical data for the last year or the allowable imbalance limit values defined in "Methodology for calculation of unavoidable losses of electricity in 110 kV and above networks" approved by the resolution of the RoA Energy Regulatory Commission dated November 19, 2001, then the EMO shall inform the party managing the Metering Complex of the imbalance as soon as possible, and the parties shall implement a visual inspection according to a mutually agreed procedure and timeline.

269. The EMO and the managing company of the Metering Complex and the Transmitter or Distributor respectively (to which network the given WEM Participant is connected) shall document the results of the visual inspection in the respective protocol, in accordance with Annex 7 of the ETN Code.

270. In a case when the visual inspection reveals that the integrity of the Metering Complex is damaged (current and potential transformer, meters, or separate details are broken or non-functional, seals are injured or removed or tampered with, secondary circuit

wires are broken, the design-based electric circuit is changed, or the Metering Complex is in any way tampered with), it shall be presented to the Metrological Body in the procedure and timeframe mutually agreed among the parties with the aim to conduct an extraordinary calibration of the meters, current and potential transformers of the Metering Complex.

271. Extraordinary calibration of the meters, current and potential transformers of the Metering Complex shall be conducted in accordance with Provision 256 of the ETN Code.

272. When an integrity failure of the Metering Complex is not detected during the visual inspection, and:
    1) The imbalance is beyond the statistical data, but is in the allowable imbalance limit range, such deviation shall be deemed acceptable, and recalculations shall not be performed.
    2) The imbalance is outside the allowable imbalance limit range, such deviation shall be presented to the Metrological Body in the procedure and timeframe agreed mutually among the parties with the aim to conduct an extraordinary calibration of the meters, current and potential transformers of the Metering Complex.

273. In cases prescribed in Provision 270 and sub-Provision 2) of Provision 272 of the ETN Code, the EMO shall recalculate the electricity, compiling a relevant protocol (act) on the results of the recalculation. Recalculation shall be performed based on the data of the control meters for the calendar month when the Commercial metering failure is detected. If the recalculation is not possible to perform based on the data of the control meters, the EMO shall perform it based on the other Metering Complexes involved in the DAS, data of their balance groups, and conclusion issued by the Metrological Body. In such a case, the conclusion of the Metrological Body shall include data on the integrity of or damage to the devices that are part of the Metering Complex, on

meter readings as well as on the results of the accuracy check of their performance.

274. If the integrity failure of the Meter Complex is detected by the managing company of the Metering Complex or the Transmitter or Distributor respectively (to which network the given WEM Participant is connected), the latter shall inform the EMO by the end of the next business day starting from the failure detection moment and be guided by the EMO instructions, making records in the respective logbook. In the case described in this Provision, the parties shall be managed by procedures prescribed in Provision 273 of the ETN Code within 72 hours.

275. To check its metering data, the WEM Participant shall have a right to enter the territory of another WEM Participant, with prior consent of the latter, to read its data from the Metering Complexes.

Annex N1

REPUBLIC OF ARMENIA ELECTRICITY SYSTEM RELIABILITY AND SECURITY INDICATORS

CHAPTER 1. GENERAL PROVISIONS

1. The RS Indicators shall describe the reliability and security of the Electricity System.
2. The RS indicators are classified into the following groups:
   1) RS Indicators by states;
   2) RS Indicators by frequency;
   3) RS Indicators by voltage;
   4) RS Indicators by capacity reserves;
   5) RS Indicators by static and dynamic stability;
   6) RS Indicators by automated regulation systems;
   7) RS Indicators by system automation control.

CHAPTER 2. RS INDICATORS BY STATES

3. Assessment of the performance of RS Indicators shall be carried out for:
   1) Nk: Normal state of the Electricity System, when the elements k = 0, 1, 2, 3... are under repair;
   2) Nk-1: Normative contingencies.
4. Normative Contingencies shall be classified into the following groups:
   1) Group I – the most frequently occurring contingencies:
      a) Emergency outage of a network element as a result of unsuccessful action of the Automatic Recloser (ARC), except for the outage of busbars, outage of the intersystem connection lines as a result of unsuccessful action of the Single-phase Automatic Recloser, outage of one

connection at the cross-section of the Electricity System due to unsuccessful ARC action;

   b) Emergency outage of a generation unit of up to 250 MW of installed capacity.

2) Group II - Exceptional contingencies:
   a) Emergency outage of double-circuit transit transmission lines (TL) by means of unsuccessful ARC action,
   b) Emergency outage of any of the busbars of the distribution facility at a power plant or a sub-station,
   c) Contingency shutdown of a reactor unit or of a generation unit of a power plant, the installed capacity of which exceeds 250 MW.
3) Group III - Extraordinary contingencies:
   a) Simultaneous outage of two and more independent TLs, by means of unsuccessful ARC action,
   b) Emergency outage of two busbars of a distribution facility at a power plant or a sub-station.

5. The RS Indicators and requirements for their performance by states are introduced in the below table:

RS INDICATOR	STATES OF THE ELECTRICITY SYSTEM			
	N_k $(N_1, N_2, ..., N_k)$	N_{K-1} (Group I)	N_{K-1} (Group II)	N_{K-1} (Group III)
1	**2**	**3**	**4**	**5**
1) Ensuring electricity supply according to demand (reliability indicator)	I	I	III	III
2) Ensuring necessary capacity reserve of the system (primary, secondary, and tertiary) (reliability indicator)	I	II	III	III
3) RS Indicators by frequency: a) Ensuring quality of electricity (reliability indicator)				
· Long-term	I	II	III	III
· Short-term	I	I	III	III
b) Ensuring stability of the Electricity System (security indicator)				
· Long-term	I	I	II	III
· Short-term	I	I	II	III
c) Ensuring security of elements of or electric installations connected to the Electricity System (security indicator)				
· Long-term	I	I	II	II
· Short-term	I	I	II	II
4) Performance of RS Indicator by voltage: a) Ensuring settlement values of voltage at Boundary points of the Electricity System (reliability indicator)				
· Long-term	I	II	III	III
· Short-term	I	I	III	III

RS INDICATOR	STATES OF THE ELECTRICITY SYSTEM			
	N_k (N_1, N_2, ..., N_k)	N_{K-1} (Group I)	N_{K-1} (Group II)	N_{K-1} (Group III)
1	2	3	4	5
b) Ensuring static stability of load at nodes of the Electricity System (security indicator)				
· Long-term	I	I	II	III
· Short-term	I	I	II	III
c) Ensuring security of elements of the Electricity System or electric installations connected to the Electricity System				
· Long-term	I	I	II	II
· Short-term	I	I	II	II
5) Ensuring static and dynamic stability of the Electricity System (security indicator)				
· Long-term	I	I	II	III
· Short-term	I	I	II	III

6. In Provision 5 of this Annex in case of the sign "I' maintenance of the given Indicator is mandatory without application of automated measures or interference of the ESO Dispatcher; in case of the sign "II" maintenance of the Indicator is mandatory with application of automated measures or interference of the ESO Dispatcher; and in case of the sign "III" maintenance of the Indicator is not mandatory.

CHAPTER 3. RS INDICATORS BY FREQUENCY

7. The performance of RS Indicators of the Electricity System by frequency in cases prescribed by the ETN Code is ensured through primary, secondary, and tertiary regulation of frequency as well as operation of control systems.
8. To ensure the reliability of the Electricity System, the following permitted ranges of frequency change are set:

RANGE OF PERMITTED CHANGE OF FREQUENCY	INDICATORS, HZ
1) Long-term	50±0.1 no less than 95% of the week time
2) Short-term	50±0.2 no less than 98.5% of the week time
3) Maximum dynamic change range after Group I contingency (load shedding must not respond)	50±0.8
4) Permissible range after Group I contingency	50±0.4 no more than 15 minutes

9. To ensure security of the Electricity System, the following permitted ranges of frequency change are set:

RANGE OF PERMITTED CHANGES OF FREQUENCY	INDICATORS IN HZ
Long-term	49.0 – 50.4
Short-term	48.0– 49.0 for 2 minutes 47.7 – 48.0 < 30 seconds 47.5 - 47.7 < 4 seconds < 47.5 must be excluded f≤49.0-49.5 Hz and $\frac{df}{dt} \geq 2 - -2.5 \frac{Hz}{sec}$ for 0.1seconds, 50.5-51.0 for < 3 minutes, 51,0-52,5 *for the time set according to the factory instructions for turbines* >52.5 - must be excluded

CHAPTER 4. RS INDICATORS BY VOLTAGE

10. In a N_k situation, the voltages at the nodes of the Electricity System shall be regulated considering the potential occurrence of any N_k -1 normative contingency (Group I N_k -1, Group II N_k-1, and Group III N_k-1 contingencies).
11. To ensure the reliability of the Electricity System during Group I N_k and N_k-1 contingencies, the voltage regulation and control must be made through the control points of the Electricity System by the ESO.
12. To ensure the security of the Electricity System during N_k and N_k-1 situations (any Normative contingency), the value of voltage in each load node shall ensure the static stability of the load by voltage and shall be determined based on the voltage reserve coefficient K_U for the given node, which is calculated by the following formula:

$$K_U = \frac{U - U_{cr}}{U}$$

U – the voltage level at the load node under the given regime of the Electricity System.

U_{cr-} – the critical voltage at the load node, which corresponds to the marginal value of static stability of electric engines. At nodes of 110 kV and higher voltage burden, the critical voltage accepted is not less than 0.7 and 0.75 $U_{nom,,}$ unless other more accurate data is available.

13. The requirements for static stability of the load in the Electricity System are as follows:
    1) The coefficient K_U should be not less than 15 percent for a N_k situation in the Electricity System, and not less than 10 percent in any N_k - *1* (any Normative contingency).
    1) In case of Group I N_k and N_k-*1* contingencies in the Electricity System, the static stability shall be maintained by voltage level at each load node without the application of system automation control, and in the event of Group II N_k-*1* contingencies, with the application of system automation control.
14. Security of equipment of the Electricity System with regard to voltage increase must be ensured. Voltage levels at the nodes should not exceed the maximum long-term permissible operating voltage levels for that equipment, and the short-term permissible voltage jump should not exceed the duration limits defined for that equipment.

CHAPTER 5. RS INDICATORS BY CAPACITY RESERVES

15. If imbalances occur between generated and consumed capacities, frequency and capacity regulation shall be implemented through the involvement of primary, secondary, and tertiary capacity reserves as defined in the ETN Code.
16. The primary reserve capacity of the synchronous zone is planned for automatic restoration of the balance between generation and

consumption after the emergency outage of the largest unit, thus preventing automated load shedding by frequency (ALSF). The primary reserve is intended to participate proportionally in the formation of the primary reserve of the synchronous zone, in order to participate in the process of general frequency regulation of the synchronous zone or to ensure frequency regulation in the isolated zone of the Electricity System.

17. Indicators of the primary reserve capacity are the following:
    1) The minimum primary capacity reserve of the synchronous zone ($\Delta P^{I}_{s.z.r.}$), which must be no less than the capacity of the largest unit of that synchronous zone,
    2) The minimum primary capacity reserve ($\Delta P^{I}_{\mathrm{h}}$) within the synchronous zone of the Armenian Electricity System, which should be no less than the amount determined by the proportional principle as follows:

$$\Delta P^{I}_{\mathrm{h}} \geq \Delta P^{I}_{s.z.r.} \frac{P_{\mathrm{h}}}{P_{s.z.}},$$

    here P_h, Ps.z. are active capacity generation of the Electricity System and synchronous zone, respectively.
    1) In a situation that occurs due to the contingency outage of the largest unit of the synchronous zone and frequency regulation, the primary reserve capacity must be fully utilized in 30 seconds and 50 percent of that in 15 seconds.
    2) The units (generators) supplying the primary reserve capacity must be capable of providing such supply for at least 15 minutes.
    3) In the case of isolated mode of Electricity System operation, the ESO shall decide on the requirement for and the size of the primary reserve capacity to be involved.

18. The secondary capacity reserve aims to recover the used primary reserve capacity, the planned intersystem flow, and frequency

within minutes after Group I contingency.

19. The indicators for secondary reserve are as follows:

    1) The minimum size of secondary reserve capacity must be sufficient to recover the used primary reserve capacity and to fully compensate for non-regulated changes in the Electricity System. It is determined as follows:

$$\Delta P_r^{II} \geq \sqrt{a \cdot L_{max} + b^2} - b,$$

    where:

    L_{max} is the maximum expected consumption peak in the Electricity System during the period observed (MW)

    a = 10 MW

    b= 150 MW.

    1) The secondary reserve capacity must be ready to be launched in 30 seconds after the onset of an imbalance, reaching its maximum value in 15 minutes without preventing the supply of the primary reserve capacity.

    2) In the event of isolated mode of operation, the ESO shall decide on the requirement for and size of the secondary capacity reserve to be involved. The reserve should be considered only on the hydropower plants (HPP) without any change in the planned irrigation water flow.

20. The tertiary reserve capacity is intended to operatively in up to 30 minutes supplement and then restore the used secondary reserve capacity, thus ensuring that the Electricity System stands ready to respond to the next loss of generation.

21. The indicators for tertiary reserve are as follows:

    1) The size of the tertiary reserve capacity must be sufficient to recover the used capacity of the secondary reserve.

    2) The tertiary reserve capacity must be ready to be launched within 15 minutes after the onset of the imbalances and reach its maximum value within 30 minutes.

    3) The requirement and size of the tertiary reserve capacity

in the event of isolated mode of operation of the Electricity System must be determined by the ESO. The reserve should be considered only on the hydropower plants without any change in the planned irrigation water flow.

CHAPTER 6. RS INDICATORS BY STATIC AND DYNAMIC STABILITY

22. The requirements set for the static and dynamic stability of the Electricity System are as follows:

CHARACTERISTICS OF CONTINGENCIES	GROUPS OF CONTINGENCIES	STABILITY MAINTAINED
1	2	3
1) Emergency outage of a network element as a result of unsuccessful action of the ARC, except for: a) Outage of busbars; b) Outage of the intersystem connection lines as a result of unsuccessful action of the Single-phase Automatic Recloser; c) Outage of one connection at the cross-section of the Electricity System due to unsuccessful ARC action. 2) Emergency Outage of up to 250 MW generation (installed) capacity.	Group I	I II I
3) Emergency outage of double circuit transit transmission lines by unsuccessful ARC; 4) Emergency outage of any of the busbars of the distribution facility at a power plant or substation; 5) Contingency shutdown of the reactor unit or of the generation (installed) capacity over 250 MW.	Group II	II

6) Simultaneous outage of two and more independent transit transmission lines by unsuccessful ARC; 7) Emergency outage of two busbars of the distribution facility at a power plant or substation.	Group III	III

23. In Provision 22 of this Annex in case of the sign "I' maintenance of the given Indicator is mandatory without application of automated measures or interference of the ESO Dispatcher; in case of the sign "II" maintenance of the Indicator is mandatory with application of automated measures or interference of the ESO Dispatcher; and in case of the sign "III" maintenance of the Indicator is not mandatory.
24. At each cross-section of the Electricity System, the active capacity shall not exceed the maximum permissible active power (Pmax), which should provide for a long-term permissible reserve of static aperiodic stability for not less than 20 percent and short-term (up to 15 minutes) permissible reserve for not less than 8 percent; it should also satisfy the following conditions:
    1) in any long-term contingency situation:

$$P_{max} \leq 0{,}8\, P_{lim.}^{st.stab} - \Delta P_{irr.osc}$$

    2) in any short-term Group I N_{k-1} contingency situation:

$$P_{max} \leq 0{,}92\, P_{lim.}^{st.stab} - \Delta P_{irr.osc}$$

where:

$P_{lim}^{st.stability}$ – static aperiodic stability boundary capacity limit for the given segment.

$\Delta P_{irr.osc.}$ – irregular load flow oscillations caused by oscillations at the generation and consumption sides of a given section.

25. In the case of a Group I N_k-1 contingency situation in the Electricity

System, both static and dynamic stability of the system are ensured without the application of special system automation control.

26. In the case of a Group II Nk-1 contingency in the Electricity System, for maintaining static and dynamic stability of the system, application of special system automation control is allowed.
27. In the case of a violation of Electricity System stability (onset of asynchronous state), automated separation of the appropriate segment of the Electricity System should be planned to avoid the development of a cascading fault.
28. The static and dynamic stability of the Electricity System shall be calculated using a verified model. The verification of the model shall be implemented by reproducing several transient processes that actually took place and have been registered in the unified system that monitors transient electromechanical processes in the Electricity System and comparing them with actual changes of calculated operating parameters.

CHAPTER 7. RS INDICATORS BY AUTOMATED REGULATION SYSTEMS

29. The automatic excitation regulators of generators connected to the Electricity System shall operate under a voltage control regime and have a 4–5 percent regulation imbalance.
30. The primary and secondary regulation of frequency and capacity in the Electricity System shall be implemented in an automated manner, whereas the tertiary regulation shall be implemented in an operative manner (by dispatching), in cases prescribed by the ETN Code.
31. RS Indicators of automated primary and secondary regulation of frequency and capacity in the Electricity System are as follows:

REGULATION SYSTEM	TYPE OF INDICATOR	VALUE OF INDICATOR
1) Primary	Ranges of frequency regulation	50±0.1 Hz not less than 95 percent of the day 50±0.2 Hz not less than 98.5 percent of the week 50±0.4 Hz not more than 15 minutes after the contingency started
	Maximum range of frequency dynamic change after Group I contingency	50±0.8 Hz
	Activation (general/ normalized)	50±0.15/50±0.1 Hz
	Dead zone (general/ normalized)	50±0.075/50±0.05 Hz
	Disparity in regulation	4 percent at thermal plants, 5 percent at nuclear plants, 4–6 percent at hydropower plants
	Speed of response of the reserve capacity	50 percent – not more than 15 seconds 100 percent – not more than 30 seconds
	Total duration of supply of the reserve capacity	Not less than 15 minutes
2) Secondary	Speed of response of the reserve capacity	100 percent – not more than 15 minutes
	Total duration of supply of the reserve capacity	Not less than 30 minutes
	Accuracy of measurement of frequency and capacity	1.5mHz and not more than 2%

CHAPTER 8. RS INDICATORS BY SYSTEM AUTOMATION CONTROL

32. The System Automation Control of the Electricity System is designed to prevent the occurrence and spread of emergency states and their elimination. The type of impact and values of the

System Automation Control subsystems, the operational principles and settings of the devices, and their impact on the Electricity System shall be selected in such a way as to ensure coordinated operations of the devices (selective, rapid, sensitive, and reliable).

33. The following functions shall be performed by the action of the System Automation Control in the Electricity System:
    1) Automated prevention of stability violation (APSV);
    2) Automated elimination of asynchronous mode (AEAM);
    3) Automatic limitation of frequency drop;
    4) Protection against frequency increase (PFI);
    5) Special automated load shutdown;
    6) Voltage down automated limitation (VDAL);
    7) Voltage up automated limitation (VUAL);
    8) Automated separation from frequency drop at power plants (ASFD);
    9) Automated prevention of equipment from impermissible overloading.
34. APSV is designed to ensure the dynamic and static stability of the Electricity System in case of a Group II contingency in Normal state of Electricity System operation (allowed for Group III contingencies as well, but not mandatory).
35. APSV must be implemented in those cross-sections of the Electricity System that are risky for stability due to Group II contingencies.
36. Selectivity, sensitivity, and rapidness of the APSV must ensure the stability of the Electricity System, and it must have sufficient impact and be minimal at the same time.
37. Impact modes of APSV on the Electricity System must be chosen from the following list:
    1) Short-term (impulse-induced) or long-term load shedding at thermal power plants, with boilers that are equipped with automatic regulators of steam production;
    2) Generator shutdown;

3) Disconnection of consumers;
4) Forcing of the generators' excitation (excitation boost);
5) Division of the Electricity System into non-synchronous parts.

38. Implementation of AEAM in the Electricity System is mandatory if:
    1) The violation of stability of the Electricity System synchronous operation and occurrence of asynchronous mode jeopardize the security of the system due to the development of a cascading fault and damage to the equipment;
    2) The violation of parts of the Electricity System or any power plant or separate generator synchronous operation, and, consequently, occurrence of asynchronous mode cannot be excluded as a result of sudden or probable occurrence of Group III contingencies of the Electricity System, wrong planning or regulation of operation mode, APSV breach, and other cases.

39. In the Electricity System design and annual dispatch planning processes, the Electricity System stability and asynchronous mode calculations (modeling) as well as experience from analysis of previous operation of the grid must be used to determine where the AEAM equipment should be placed at dangerous connections of the sections and lines.

40. Asynchronous mode between the power plant and the Electricity System must be eliminated through automated separation, either as main or as reserve operation.

41. AEAM devices must ensure the detection and elimination of both complete phase and incomplete phase of asynchronous mode.

42. To ensure selectiveness of operation of AEAM, principles and settings of devices must exclude the operation of AEAM during the synchronous oscillations and short circuits as well as asynchronous modes that occur outside of the control of the given devices.

43. The settings of AEAM devices must satisfy the sensitivity of AEAM operation in case of occurrence of asynchronous mode.

44. Speed of operation of AEAM devices on 400 kV lines and 220 kV connections must prevent transformation of a long-term two-frequency asynchronous mode into a multi-frequency asynchronous mode and ensure the security of the equipment.
45. To back up the operation of AEAM devices and switches, at least two AEAM devices must be installed at each section of 110 and 220 kV lines that are at risk of asynchronous mode occurrence, and on both sides of 400 kV lines.
46. Any asynchronous mode of a generator (toward the power plant) connected to the transmission network should be eliminated by its automatic shutdown.
47. To ensure the successful separation of the Electricity System in asynchronous mode, AEAM device operation should aim for the location it is placed, i.e., without communicated dispatch instruction. Yet, dispatch instruction for separation in another location by communication is allowed in cases when the backup automated separation was performed on the site.
48. Electricity System separation points should be justified by the result of modeling and operation analysis and should ensure the restoration of the normal operation state of the Electricity System as soon as possible.
49. In the event of active power deficiency (shortage), the Automatic limitation of frequency drop sub-system should ensure the performance of Electricity System security (stability) indicators by frequency by eliminating the impermissible frequency drop (decline) and restoration and should include the following operations:
    1) Automated startup and loading by frequency (ASLF);
    2) Automated load shedding by frequency (LSF), including
        a. Automated prevention of frequency drop (LSF-1);
        b. Automated restoration of frequency (LSF-2);
    3) Automated load shedding by frequency drop rate (ALSFDR);
    4) Automated reclosing by frequency (ARF);

5) Electricity System automatic separation from the neighboring system.

50. ASLF should automatically reduce the deficiency of active capacity in case of frequency drop (decline) to reduce or prevent (depending on the magnitude of deficiency) disconnection of consumers due to LSF. ASLF must operate if the frequency declines to 49.4–49.2 Hz.

51. Upon request of the ESO, the ASLF devices must be installed at HPPs with capacity of 20 MW and over.

52. In the event of active capacity deficiency, LSF, by means of preventing an impermissible frequency drop (decline) and restoration, should ensure the security of the Electricity System according to the frequency indicators according to the following principles:

1) LSF-1 is intended to suspend the frequency drop (decline) to 47.5 Hz in cases when the deficiency of active capacity in the Electricity System does not exceed 45 percent of Electricity System capacity separated from the synchronous zone or maximum load capacity of any of its nodes. The frequency settings of the operation must be implemented within the range of 48.8–47.5Hz with 0.1 Hz per step and a time delay of 0.1–0.2 seconds, and the capacity of the load to be disconnected by LSF-1 is:

$$\Delta P_{LSF-1} \geq \Delta P_{def.} + 0.05 * P_{load} \ ,$$

where ΔP_{def} is the generated capacity deficiency, P– maximum load in the Electricity System or over any node.

2) LSF-2 is intended to restore the frequency after the LSF-1 down operation;

3) The volume of the LSF-2 must be fully combined with the LSF-1 volume and should operate for the disconnection of the same consumers;

4) The LSF-2 frequency setting must be within the range of

48.8-48.6Hz, with the time set at 4–60 seconds. The step for the time setting is 4 seconds.

53. In case of significant deficiencies (where the active capacity deficiency is over 45 percent), ALSFDR should prevent a severe decline of frequency and accelerate the restoration
54. The principle of setting the operation of ALSFDR devices must be based on measuring values of frequency and its decline rate and comparing them with the corresponding given settings.
55. Settings of the ALSFDR devices must be regulated:
    1) In the range of 49–49.5 Hz, by frequency;
    2) In the range of 2.0–2.5Hz/sec, by frequency decline rate;
    3) Holding time for 0.1 seconds.
56. Disconnection of a load from the ALSFDR must exclude frequency decline to 47.5 Hz in cases where Electricity System active capacity deficiency exceeds 45 percent of the maximum capacity of consumption.
57. The automated reclosing by frequency (ARF) sub-system should automatically restore electricity supply to consumers disconnected by LSF after frequency restoration.
58. ARF operation settings should be implemented at the 49.4–49.8 Hz range with a time delay of not less than 5 seconds, with a 5-second step set for the time.
59. After each sequence of ARF, the connecting load should not cause a double operation of LSF and should not exceed 2 percent of the total load disconnected by LSF.
60. The protection against frequency increase (PFI) sub-system should prevent impermissible increases of frequency in the Electricity System to levels at which security protection of TPPs and nuclear power plant (ANPP) turbines will operate.
61. PFI operation must be performed by frequency within the range of 50.8–51.2 Hz and with a 0.15 second time delay.
62. PFI devices must switch off the generators. Hydro generators must be switched off first.

63. In case of significant loss of generation capacity in the Electricity System, the special automated load shutdown devices should prevent:
    1) Disconnection of the interconnection line from the neighboring system;
    2) Impermissible drop of voltage at Electricity System nodes.
64. Voltage down automated limitation (VDAL) should automatically prevent an impermissible drop of voltage, avoiding a violation of stability of the Electricity System node loads by voltage.
65. VDAL devices should control the levels and duration of voltage drops at Electricity System nodes or the rate of voltage drop and/or the reactive capacity.
66. VDAL devices operation must be implemented by the reactive power compensation or operational modification of the state on the 220 kV or lower-voltage grid and/or by disconnecting consumer load, and on a higher-voltage grid only through reactive power compensation or modification of the operational state.
67. Operation of VDAL devices must be coordinated with the operation of relay protection devices, reserve feeding automatic connection, and automatic reclosing devices.
68. Voltage up automated limitation (VUAL) should prevent impermissible voltage increases (by value and duration) to the equipment.
69. VUAL devices must be placed on each side of 110 kV and higher voltage lines, the unilateral disconnection of which can cause an impermissible voltage increase to the equipment.
70. VUAL devices operating principles must be implemented to control voltage level increases and the duration of each phase as well as values of reactive capacities and direction in the line.
71. VUAL devices operating settings must ensure the security of the equipment.
72. Operation of VUAL devices must be implemented in two degrees depending on the magnitude of voltage:

1) First degree with time delay should be aimed at changing the mode of operation of equipment to compensate for reactive power or operational modification of the state;
2) Second degree should work with a bigger time delay than the first degree and be aimed at two-end disconnection of a line and implementation of three-phase automated reclosing.

73. Automatic separation sub-system should ensure the security of the Electricity System by automatically separating from the neighboring system when a severe emergency threatens to violate the following security indicators of the Electricity System:
    1) Electricity System permissible frequency range;
    2) Permissible voltage levels at the nodes of the Transmission network;
    3) Permissible range of load for any element of the Electricity System;
    4) Electricity System stability.
74. The restoration (after separation of the Electricity System from a neighboring system) of the Normal operating state of the Electricity System automatically and/or by instruction of the dispatcher must be carried out in accordance with the plan of actions for situations requiring unavoidable limitation of electricity supply approved by the Commission.
75. In case of a frequency drop at Electricity System power plants, the Automated separation from frequency drop devices (ASFD) for TPPs or a part of TPPs must prevent a shutdown of the plant resulting from the violation of the work of mechanisms for own needs, impermissible vibrations of the turbines, or risk of damage to the blades and base. If the frequency range has dropped to less than 47.5 Hz:
    1) Settings for the ASFD device operation at TPPs must be regulated in two steps:
        a) First step: 47.2 - 47.5Hz / 4–6 seconds;
        b) Second step: 47.0 - 47.2Hz / 0.15–0.5 seconds.

2) Stable operation of TPP unit for own needs must be ensured for not less than for 30 minutes.

76. ASFD devices at HPPs:
   1) Shall be designed to ensure the restart of disconnected TPP and ANPP generators, to keep running a certain portion of generators with their associated consumers in case of emergencies accompanied by severe loss of capacity in the Electricity System or its nodes, and to separate HPP through the action of ASFD using an estimated balanced load.
   2) Settings for the operation of the ASFD devices at HPPs must be regulated in two steps:
      a) First step: 47.2 - 47.5Hz / 4 - 6 seconds;
      b) Second step: 47.0 - 47.2Hz / 0.15 - 0.5 seconds.

Annex N 2

INFORMATION ON AVAILABLE CAPACITIES

____

(title of the company)

Available capacity in 20___

MW

N	MONTH	1	2	3	4	5	6	7	8	9	10	11	12
	DATE	1-31	1-28 1-29	1-31	1-30	1-31	1-30	1-31	1-31	1-30	1-31	1-30	1-31
1.	Rated capacity, including (by facility and equipment):												
1)													
2)													
2.	Planned outage of the capacities, including:												
1)													
2)													
3.	Summary limitation, including:												
1)	Capacity limitations due to climatic conditions												
2)	Limitations due to thermal load												

3)	Limitations due to deterioration of equipment												
4.	Manageable capacity in condensing state, including:												
1)													
2)													
5.	Available capacity in the heating state, including:												
1)													
2)													

1. The columns of the above table can be further broken down by days.
2. Minimal required technical capacity is ______MW (filled out upon necessity).

Representative of the Company ______________________________

Name, Surname /signature/

APPLICATION TO OBTAIN TECHNICAL CONDITIONS FOR CONNECTION TO THE TRANSMISSION NETWORK

<table>
<tr><td>1.</td><td colspan="6">Information about Applicant</td></tr>
<tr><td>1)</td><td colspan="6">Name</td></tr>
<tr><td rowspan="4">2)</td><td rowspan="4">Type of the Applicant</td><td colspan="4">Generator</td><td></td></tr>
<tr><td colspan="4">Distributor</td><td></td></tr>
<tr><td colspan="4">Qualified Customer</td><td></td></tr>
<tr><td colspan="4">Entity intending to obtain a Qualified Customer status</td><td></td></tr>
<tr><td>3)</td><td colspan="6">Name of the facility</td></tr>
<tr><td>4)</td><td colspan="6">Address of the facility</td></tr>
<tr><td>5)</td><td colspan="6">Surface of the facility to connect according to the cadaster (including the plan)</td></tr>
<tr><td rowspan="4">6)</td><td rowspan="4">Purpose of connection</td><td colspan="4">Connection of new facility</td><td></td></tr>
<tr><td colspan="4">Increase of installed capacity</td><td></td></tr>
<tr><td colspan="4">Increase of Distributor load</td><td></td></tr>
<tr><td colspan="4">Upgrade of the existing facility</td><td></td></tr>
<tr><td>7)</td><td colspan="6">Planned increase (MW) of the upgraded or increased capacity</td></tr>
<tr><td>8)</td><td colspan="6">Planned level of voltage of the connection point (kV)</td></tr>
<tr><td>9)</td><td colspan="6">Stages of implementation (yes/no)</td></tr>
<tr><td rowspan="3">10)</td><td rowspan="3">Construction/upgrade period (by stages)</td><td>Stage</td><td>I</td><td>II</td><td>III</td><td>IV</td></tr>
<tr><td>Year/month</td><td></td><td></td><td></td><td></td></tr>
<tr><td>MW</td><td></td><td></td><td></td><td></td></tr>
<tr><td>11)</td><td colspan="6">Address of the Applicant:</td></tr>
<tr><td>12)</td><td colspan="6">Telephone:</td></tr>
<tr><td>13)</td><td colspan="6">Fax:</td></tr>
<tr><td rowspan="4">14)</td><td rowspan="4">Responsible person</td><td colspan="2">Name, surname</td><td colspan="3"></td></tr>
<tr><td colspan="2">Address</td><td colspan="3"></td></tr>
<tr><td colspan="2">Email</td><td colspan="3"></td></tr>
<tr><td colspan="2">Telephone</td><td colspan="3"></td></tr>
</table>

This part is filled by Generators

2	**Information about Generating Facility**				
1)	Type of the generating facility	Hydro (run of)			
		Impoundment facility			
		Hydro Reservoir			
		Nuclear			
		Thermal			
		Combined cycle			
		Wind			
		Other (specify)			
2)	Fuel	Coal			
		Gas			
		Oil			
		Nuclear			
		Other (specify)			
3)	Energy data by stage	I	II	III	IV
a.	Number of units				
b.	Active power generation (MW)				
c.	Maximum capacity (MW)				
d.	Annual generation forecast (MWh)				
4)	Capacity to regulate reactive energy (yes/no)				

This part is filled by the Distributor and Qualified Customer

3	**Information about Connection Facility**				
1)	Type of facility	Industrial			
		Industrial for own purposes			
		Traction			
		General purpose			
		Other (specify)			
2)	Information by stage	I	II	III	IV
a.	Forecast maximum active load (MW)				
b.	Forecast maximum total load (MVA)				
c.	Forecast minimum active load (MW)				
d.	Annual generation (MWh)				
e.	Maximum power generation capacity of its own (MW)				
f.	Annual power generation capacity of its own (MWh)				

Representative of the Company ________________________________

Name, Surname /signature/

Annex N 4

APPLICATION FOR CONNECTION PERMISSION

1.	**Information about Applicant**		
1)	Name		
2)	Type of the Connecting Applicant	Generator	
		Distributor	
		Qualified Customer	
		Entity intending to obtain a Qualified Customer status	
3)	Name of the facility		
4)	Address of the facility		
5)	Surface of the facility to connect according to the cadaster (including the plan)		
6)	Purpose of the connection	Connection of new facility	
		Increase of installed capacity	
		Increase of Distributor load	
		Upgrade of the existing facility	
7)	Term for connection or obtaining the permission for connection		
8)	Construction stages		
9)	Term for completion of the construction (reconstruction)		
10)	Planned capacity of the new or reconstructed connection (MW)		
11)	Planned voltage levels at the point of connection (kV)		
12)	Connection address		
13)	Telephone		
14)	Fax		
15)	Responsible person	Name, Surname	
		Address	
		Email	
		Telephone	

This part is filled in by Generators:

2.	**Information about Generating Facility**				
1)	Type of facility	Nuclear			
		Hydro (specify type)			
		Thermal (specify type)			
		Wind			
		Other (specify)			
2)	**Fuel used in thermal and combined cycle facilities**	Coal			
		Gas			
		Oil			
		Other			
3)	**Energy data**	**Existing**			
a.	Number of boilers				
b.	Number of generators				
c.	Number of step-up transformers				
d.	Overall capacity (MVA)				
e.	Active capacity (MW)				
f.	Reactive capacity (MVAr)				
g.	Maximum active supplied capacity (MW)				
h.	Minimum active supplied capacity (MW)				
i.	Forecast annual production (MWh)				
j.	Nominal voltage of own purposes (kV)				
k.	Maximum active capacity for own purposes (MW)				
l.	Maximum reactive capacity for own purposes (MVAr)				
m.	Capacities to regulate reactive power (yes/no)				
4)	**Information about generator (for each one)**	**1**	**2**	**3**	**4**
a.	Generator model				
b.	Total capacity (MVA)				

c.	Active capacity (MW)					
d.	Power factor (cosϕ)					
e.	Nominal voltage (kV)					
f.	Spinning numbers					
g.	Type of excitation system (spinning/static)					
h.	Type of voltage regulation and system stabilizer					
i.	Short circuit factor					
j.	Synchronous reactive resistance, Xd/ Xq (%)					
k.	Transient reactive resistance, Xd'/Xq' (%)					
l.	Over transient reactive resistance, Xd''/Xq'' (%)					
m.	Time constant, Td/ Tq (sec.)					
n.	Transient time constant, Td'/Tq' (sec)					
o.	Over transient time constant, Td''/Tq'' (sec)					
p.	Generator and turbine inertia torque, GD2 (N*m2)					
5)	**Information about turbines (for each one)**		**1**	**2**	**3**	**4**
a.	Turbine model					
b.	Installed capacity (MW)					
c.	Technical minimum (MW)					
6)	**Information about transformers (for each one)**		**1**	**2**	**3**	**4**
a.	Model of transformer					
b.	Nominal factor of transformer (kV/kV)					
c.	Nominal capacities HV/MV/LV (MVA)					
d.	Voltage of short circuit (%)	Usc 1-2				
e.	Power of short circuit (kW)	Usc 1-3				
		Usc 2-3				
		Psc 1-2				
		Psc 1-3				
		Psc 2-3				
f.	Idle power, I (%)					
g.	Loss of idle power, P (kW)					

h.	Voltage regulation (under load, no load)						
i.	Converter range and step (%)						
j.	Connection group						
k.	Positive sequence resistance						
l.	Zero sequence resistance						
m.	Neutral grounding						

This part is filled by the Distributor and Qualified Customers

3.	**Information about Connection Facility**		
1)	Type	Industrial	
		Industrial with own production capacities	
		Traction	
		General	
		Other	
2)	**Energy data**	**Existing**	**New**
a.	Installed capacity (MW)		
b.	Power factor (cosϕ)		
c.	Anticipated maximum capacity (MW)		
d.	Anticipated minimal capacity (MW)		
e.	Daily graph of anticipated load (daily graph of active and reactive power by winter and summer state (yes/no)		
f.	Load sensitivity over fluctuations of voltage and frequency (describe)		
g.	Maximum level of flickers and harmonic elements that arise due to customer load. Mention specific details related to consumption, such as industrial furnaces or traction stations that can affect the quality of power supplied to other customers.		

h.	Data about regular change of active and reactive power (>5 MVA/minute)					
i.	Gradient of active and reactive power change up/down (>5 MVA/minute)					
j.	Expected annual production volumes of its own (MWh)					
k.	Maximum annual capacity (MW)					
3)	**Information about transformers**		**1**	**2**	**3**	**4**
a.	Model of transformer					
b.	Nominal actor of transformation (kV/kV)					
c.	Nominal capacity HV/MV/LV (MVA)					
d.	Short circuit (%)	Usc 1-2				
		Usc 1-3				
		Usc 2-3				
e.	Short circuit power (kW)	Psc 1-2				
		Psc 1-3				
		Psc 2-3				
f.	Idle power, I (%)					
g.	Loss of idle power, P (kW)					
h.	Voltage regulation (loaded, no load)					
i.	Converter range and step (%)					
j.	Connection group					
k.	Positive sequence resistance					
l.	Zero sequence resistance					
m.	Neutral grounding					

Representative of the Company ________________________________

Name, surname /signature/

Annex N 5

PROTOCOL (ACT) ON INSTALLING OR CHANGING A METERING COMPLEX OR ITS ELEMENTS

«____» ________________ 20 _____   __________________________

PROTOCOL (ACT) ON INSTALLING OR CHANGING
A METERING COMPLEX OR ITS ELEMENTS

____

(name of the station, direction of the substation)

MANUFACTURER'S NUMBER OF THE METER (METERING TRANSFORMER) TAKEN OUT OF OPERATION	TYPE (MODEL)	READING OF THE METER		LAST CALIBRATION DATE	NOMINAL POWER A	NOMINAL VOLTAGE V	CURRENT TRANSFORMER		POTENTIAL TRANSFORMER	
		FROM THE BUS	TO THE BUS				FACTOR	ACCURACY CLASS	FACTOR	ACCURACY CLASS
		Tot.	Tot.							
		T1	T1							
		T2	T2							
MANUFACTURER'S NUMBER OF THE METER (METERING TRANSFORMER) INSTALLED	TYPE (MODEL)	READING OF THE METER		LAST CALIBRATION DATE	NOMINAL POWER A	NOMINAL VOLTAGE V	CURRENT TRANSFORMER		POTENTIAL TRANSFORMER	
		FROM THE BUS	TO THE BUS				FACTOR	ACCURACY CLASS	FACTOR	ACCURACY CLASS

		Tot.	Tot.							
		T1	T1							
		T2	T2							

NOTE ____

Electricity Market
Operator ____________________
Name, surname/signature/

Representative of the
Company___________________
Name, surname/signature/

Transmitter/Distributor

____
Name, surname/signature/

Annex N 6

PROTOCOL (ACT) ON SEALING TERMINAL CLAMPS AND/OR INSTALLATION BOXES OF THE COMMERCIAL METERING COMPLEXES

«____» ____________ 20 _____   ____________________

PROTOCOL (ACT) ON SEALING TERMINAL CLAMPS AND/OR INSTALLATION BOXES OF THE COMMERCIAL METERING COMPLEXES

____

(name of the station, substation)

N	SEAL INSTALLATION LOCATION	DAS IDENTIFICATION NUMBER	NUMBER OF THE REMOVED SEAL	NUMBER OF THE SEAL INSTALLED
1				
2				
3				
n				

Electricity Market Operator ____________________
Name, surname/signature/

Representative of the Company__________________
Name, surname/signature/

Transmitter/Distributor

____
Name, surname/signature/

Annex N 7

PROTOCOL (ACT) ON INSPECTION OF METERING COMPLEXES

«____» ____________ 20 _____   ____________________

PROTOCOL (ACT) ON INSPECTION OF
METERING COMPLEXES

____

(name of the station, substation)

N	DAS CODE	SEAL INSTALLATION LOCATION	MODEL OF THE METER, METERING TRANSFORMER, OR ELEMENTS	NUMBER OF THE METER, METERING TRANSFORMER, OR ELEMENT	LAST CALIBRATION	NUMBER OF THE SEAL INSTALLED	INTEGRITY
1							
2							
3							
n							

Electricity Market
Operator ____________________
Name, surname/signature/

Representative of the
Company___________________
Name, surname/signature/

Transmitter/Distributor

____
Name, surname/signature/

ACRONYMS

1. **AAF**	Annual Adequacy Forecast
2. **AEAM**	Automated Elimination of Asynchronous Mode
3. **ANPP**	Armenian Nuclear Power Plant
4. **APSV**	Automated Prevention of Stability Violation
5. **ARC**	Automatic Recloser
6. **ARF**	Automated Reclosing by Frequency
7. **AS**	Electricity System Automatic Separation from the Neighboring System
8. **ASFD**	Automated Separation by Frequency Drop at the Stations
9. **ASLF**	Automated Start-up and Loading by Frequency
10. **ASTPM**	Automated System for Technological Process Management
11. **BSP**	A Generator providing Balancing services under electricity generation license
12. **DAM**	Day-Ahead Market
13. **DAS**	Automated Data Acquisition System
14. **DCTD**	Data Collection and Transmission Device
15. **EGEN**	Annual forecast of electricity generation mix, including its adjustments on a monthly and daily basis
16. **ELTP Participants**	Utility-Scale Plants, Transmitter, Distributor, Utility-Scale Customers
17. **ELTRANS**	Annual forecast of Transmission Network Losses, including their adjustments on a monthly and daily basis
18. **EMO**	Electricity Market Operator
19. **EOM Participants**	Balancing Service Provider, Transmitter, Distributor, Utility-Scale Plants, Utility Scale Customers
20. **EPOS**	Annual Schedule of Planned Outages of the Electricity System, including its adjustments on a monthly and daily basis
21. **ERSL**	Annual Reliability and Security Level of the Electricity System, including its adjustments on a monthly and daily basis
22. **ESO**	Electricity System Operator

23. ESTPO Participants	Utility-Scale Plants, Transmitter, Distributor (only for substations and electricity transmission lines directly connected to the Transmitter), and Utility-Scale Customers
24. ETN Code	Republic of Armenia Electricity Transmission Network Code approved by the Commission
25. IPP plants	Generators operating under the Public-Private Partnership
26. LSF	Automated load shedding by frequency
27. LSF-1	Automated elimination of frequency drop
28. LSF-2	Automated restoration of frequency
29. MMS	Market Management System
30. OLTC	On-load Transformer Changer
31. PFI	Protection against Frequency Increase
32. PPP	Public-Private Partnership
33. RoA	Republic of Armenia
34. RPSA	Relay Protection and System Automation
35. RPP plants	Generators subject to tariff regulation, except for IPP plants, REPP plants, and the Balancing Service providing Generator
36. RS Indicators	Reliability and Security Indicators
37. SCADA	Supervisory Control and Data Acquisition
38. TL	Transmission Line
39. TYNDP	Ten-Year Network Development Plan
40. VDAL	Voltage Down Automated Limitation
41. VUAL	Voltage Up Automated Limitation
42. WEM Contract	Contract between WEM Participants for participation in the WEM
43. WEM Participants	Generator, Universal Supplier, Supplier, Trader, Qualified Customer, Transmitter, Distributor, ESO, and EMO
44. WEM Rules	Wholesale Electricity Market Trading Rules of the Republic of Armenia.

REPUBLIC OF ARMENIA ELECTRICITY MARKET TRANSMISSION NETWORK CODE

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