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If a whole or part of a paragraph has been amended, the date of the amending regulation appears in square brackets at the end of the paragraph. If a whole paragraph or sub-paragraph has been deleted, the date of the deletion appears in square brackets beside the deleted paragraph or sub-paragraph.

**Decision No. 1/4 of the Board of the Public Utilities Commission**

Adopted 26 June 2013

**Network Code in the Electricity Sector**

[*7 February 2018*]

*Issued pursuant to*

*Section 4, Paragraph two, Section 13, Paragraphs one and five, Section 13.1, Paragraph three, Section 25, Paragraph four, Section 36, Paragraph four, Section 37, Paragraphs one and four of the Electricity Market Law and Section 85, Paragraph one of the Energy Law*

[*17 September 2020*]

**1. General Provisions**

1. The Network Code prescribes the following:

1.1. the procedures for managing and using the electricity system (hereinafter also – the system) and the activities of the electricity system and electricity market participants (hereinafter – the market participants);

1.2. the activities of the transmission system operator in the event of a deviation from the normal operating mode or an accident in the system;

1.3. the procedures by which the transmission system operator provides transmission system services and ensures balancing and stability within the electricity system;

1.4. the procedures by which the transmission system operator registers, restricts, or refuses the planned trading operations if it is otherwise impossible to prevent transmission limitations or the overload of the transmission system, and it poses a threat to the stability of the mutually interconnected system;

1.5. the conditions for managing congestion and preventing overload of cross-border interconnections;

1.6. the technical requirements for connecting an internal line of an individual unit of immovable property to the distribution system;

1.7. the rights and obligations of market participants, balancing service providers, and the transmission system operator when providing the balancing service;

1.8. the procedures by which the transmission system operator makes balancing calculations;

1.9. the criteria and procedures by which the electricity system operator (hereinafter – the system operator) may request guarantees from electricity system participants (hereinafter – the system participants) in order to ensure payments for the balancing service;

1.10. the procedures for testing the capabilities of the transmission system operator, the distribution system operator, the defence service provider, and the restoration service provider to perform the activities laid down in the electricity system defence plan and the electricity system restoration plan.

[*17 September 2020*]

2. The following terms are used in the Network Code:

2.1. defence service – the service that ensures a capacity reserve for the safety of the system or the maintenance of automation function of electrical installations for the safety of the electricity system;

2.2. defence plan – the plan that lays down all the necessary technical and organisational measures to restore the stable operating mode of the electricity system after a technological disturbance;

2.3. compliance simulation – the inspection of electrical equipment which is carried out with the aid of mathematical calculation;

2.4. restoration service – the service that ensures the start-up of a generator without receiving external voltage to restore the operation of the electricity system in blackout condition;

2.5. restoration plan – the plan that specifies the necessary technical and organisational measures to restore the stable operating mode of the electricity system from a blackout condition;

2.5.1 relevant system operator – the system operator to whose system a power-generating module, a demand facility, a distribution system, or high-voltage direct current system is or will be connected;

2.6. automation – the set of installations that act on electrical equipment in a specific sequence without human intervention upon occurrence of predefined conditions in the electricity system;

2.7. emergency situation in the electricity system – the situation caused by an incident, a natural disaster, or other circumstances that result in a forced partial restriction or interruption of the performance of the functions of the system operator or electricity producer, posing a threat to the fulfilment of the tasks laid down in the Energy Law and the Electricity Market Law;

2.8. balancing service recipient – the market participant, within the meaning of this Code, who receives the balancing service from the transmission system operator;

2.9. [3 October 2024];

2.10. dispatch control – the process in which the system operator, following dispatch control instructions of the system operator’s dispatch control personnel, gives an order to the system participant to change the operational status and energy parameters of generating units, loads, and network elements;

2.11. dispatch control schedule generating unit (hereinafter – the DCSGU) – the individually switchable power plant generator with an installed capacity of at least 15 MW that supplies electricity to the network of the relevant system operator in conformity with the time limits and electricity volumes laid down in the dispatch control schedule, or individually switchable power plants with an installed capacity of less than 15 MW that are directly connected to the transmission system or connected to the distribution system if the system operator based on stability calculations of the electricity system can demonstrate that it is necessary to include them in the dispatch control schedule in order to maintain the stable operating mode of the electricity system;

2.12. dispatch control instructions – the document issued by the system operator and specifying the activities and sequence thereof that must be carried out by the system participant the electrical installations of which are connected to the network of the relevant system operator, and which is an integral part of the system service contract;

2.13. dispatch control order – the instruction given by the system operator to the system participant the electrical installations of which are connected to the network of the relevant system operator;

2.14. inspection of electrical equipment – measuring and evaluation of characteristics of electrical equipment, compliance testing, or simulation in order to determine the conformity of electrical equipment with technical requirements, and also to inspect operational capabilities of electrical equipment after installation, repair, or conformity with manufacturer requirements or recommendations when connecting the electrical equipment to the electricity grid of the system operator and throughout the operational life cycle of the electrical equipment;

2.15. final position – the quantity of electricity planned by the balancing service recipient for each imbalance settlement period, as notified by the balancing service recipient and approved by the transmission system operator that includes corrections in conformity with ancillary services performed in the imbalance area during the imbalance settlement period and is used for the calculation of imbalance;

2.16. generating unit – the individually switchable power plant generator and auxiliary equipment thereof;

2.17. available capacity of the generating unit – the maximum capacity, expressed in MW, that a generator can deliver to the system at a certain moment in time, taking into account the limitations of the generating unit or external conditions;

2.18. controlled dispatch control – the dispatch control process aimed at restoring the electricity system to a normal optimised operating mode;

2.19. control meter – the measuring instrument or system of measuring instruments for the accounting of the quantity of electricity and services that is used in order to obtain data about the electricity consumption if such data cannot be obtained with the aid of a commercial electricity accounting meter;

2.20. coordinated balancing area – licence operation areas of transmission system operators that have agreed on mutual cooperation for the exchange of regulation services and the organisation of a unified balancing market;

2.21. kV – kilovolts;

2.22. 2.22. MW – megawatts;

2.23. n-1 – a criterion for planning safety of the electricity system, where “n” is the number of transmission system installations (including lines, transformers, shunt reactors, capacitor banks, etc.) and generating units of at least 15 MW that enable possibility of disconnection of one of the abovementioned installations in the event of a technological disturbance, without jeopardising the stable operating mode of the electricity system;

2.24. imbalance area – commercial electricity accounting points of electricity customers and producers that are taken into account in the calculation of the imbalance caused by the balancing service recipient;

2.25. imbalance settlement period – a time period for which the imbalance is calculated;

2.26. imbalance settlement – the procedures for the financial settlement in accordance with which the transmission system operator buys electricity from the balancing service recipient or sells it thereto in order to ensure balanced operation of the electricity system;

2.27. imbalance settlement administration – activities performed by the transmission system operator to ensure imbalance settlement;

2.28. settlement period – a time period for which settlement for balancing or regulation service is made; the settlement period is one calendar month;

2.29. imbalance – the quantity of electricity within a specific imbalance settlement period that is calculated for the the balancing service recipient and corresponds to the difference between the allocated quantity of electricity attributed to this balancing service recipient and the final position of this balancing service recipient;

2.30. ancillary services contract – the contract concluded between the system operator and the system participant for the service necessary to ensure balanced operation of the electricity transmission system;

2.31. allocated quantity of electricity – the actual quantity of electricity fed into or consumed from the transmission system that is attributed to the balancing service recipient for the calculation of the imbalance caused in its imbalance area;

2.32. position – the planned quantity of electricity notified by the balancing service recipient for each imbalance settlement period;

2.33. regulation service – the ancillary service within the scope of which balancing market participants, in accordance with the procedures laid down in the contract, increase or decrease electricity generation in the electricity generation equipment under their supervision, supply stored electricity to the system, accept electricity from the system, provide the demand response service, or ensure regulation capacity;

2.33.1 regulation product – the type of the regulation service defined by the transmission system operator in cooperation with the transmission system operator of another country for the exchange of balancing energy for frequency restoration reserves with automatic or manual activation;

2.34. regulation service provider – the market participant that has concluded an ancillary services contract with the transmission system operator for the provision of the regulation service;

2.35. voltage – the effective voltage value maintained by the system operator at the connection point of electrical installations of the system participant;

2.36. technological disturbance – a breakdown, automatic disconnection, or forced disconnections of electrical equipment, unplanned disconnections of the electricity system participant, or failure to comply with the electricity quality requirements;

2.37. telemetry – remote acquisition of data from equipment connected to the electricity system;

2.38. remote signalling – remote acquisition of information about the status of switching equipment;

2.39. remote control – remote modification of the status of electrical equipment;

2.39.1 balancing market time unit – a period in which regulation product offers or regulation capacity product offers are mutually interconnected with the transmission system operator’s requests;

2.40. metering service provider – the system operator or legal or natural person authorised by it that installs and maintains accounting meters.

[*5 December 2019; 2 March 2023; 3 October 2024*]

**2. Connection to the Electricity System**

**2.1. General Obligations of the System Participants**

3. The system operator has the following obligations:

3.1. to conduct mutual discussions with the system participant regarding terms and conditions of the connection for the electricity system, during which the system operator shall provide the information that allows the system participant to evaluate the nature of the technical requirements offered by the system operator, while the system participant shall provide the system operator with comprehensive information about its intended activities;

3.2. to ensure information system solutions for the communication between the dispatch control system of the system operator and the substation or power plant communication equipment of the system participant, unless the system operator and the system participant have agreed otherwise;

3.3. to create and maintain a database of electrical equipment of the system in its licence operation area that is used for the design and installation of the system connections within the electricity system;

3.4. upon request of the system participant, to provide the necessary information for calculations of statistical and dynamic stability in relation to the design and installation of a new system connection;

3.5. to inform the system participant, within the period specified in the dispatch control instructions, about technical changes in the electricity system that may affect the operation of electrical equipment of the system participant;

3.6. to ensure dispatch control of the system participant;

3.7. for the distribution system operator, to agree with the transmission system operator on the developed technical regulations for the DSCGU electricity system connection to the distribution system;

3.8. for the distribution system operator, to connect the internal line of an individual unit of immovable property to the distribution system that is located within the licence operation area of the distribution system operator if:

3.8.1. it is installed in accordance with a building design developed in accordance with the requirements of the general construction regulations, special construction regulations, Latvian Construction Standards, and other standards;

3.8.2. its insulation conforms to the requirements of laws and regulations in force;

3.8.3. the protection zones of the line laid down in laws and regulations have been adhered to in its installation.

[*2 March 2023*]

3.1 Upon receipt of a request from the owner or prospective owner of electricity production facilities to grant an exemption from one or more provisions of Commission Regulation (EU) 2016/631 of 14 April 2016 establishing a network code on requirements for grid connection of generators (hereinafter – Regulation 2016/631) in respect of the connection of generating devices, the system operator shall prepare an assessment of this request, evaluating whether the granting of the exemption meets all of the following criteria:

3.11. it does not create discriminatory conditions for other customers in the system in respect of access to the transmission or distribution system;

3.12. it does not create competitive advantages for the owner of the generating device compared to other owners of generating devices;

3.13. it does not affect system service costs;

3.14. it does not pose risks to ensuring the stable operating mode of the network of the relevant system operator;

3.15. it does not pose risks to the fulfilment of the technical requirements laid down for the network of the relevant system operator, including disturbances and breakdowns in such equipment and devices of other customers that are connected to the network;

3.16. it does not limit or significantly affect the capacity of the electricity system;

3.17. it does not negatively affect cross-border electricity trade;

3.18. it is not possible to fulfil the provisions of Regulation 2016/631 by using reasonable technical solutions;

3.19. it generates benefits in accordance with the justification submitted by the customer in the system and the conducted cost-benefit analysis in conformity with the requirements of Article 39 of Regulation 2016/631.

[*14 December 2017; 5 December 2019*]

3.2 The system operator shall, in its request to the regulator for granting an exemption from one or more provisions of Regulation 2016/631 in respect of the connection of generating devices, include an assessment, evaluating the criteria for granting the exemption laid down in Paragraph 3.1 of this Code.

[*14 December 2017*]

3.3 Upon receipt of a request from the owner or prospective owner of an electricity-consuming installation connected to the transmission or distribution system that is used for the provision of the demand response service, or from the distribution system operator connected to the transmission or distribution system to grant an exemption from one or more provisions of Commission Regulation (EU) 2016/1388 of 17 August 2016 establishing a Network Code on Demand Connection (hereinafter – Regulation 2016/1388) in respect of the connection of an electricity-consuming installation, a distribution installation connected to the transmission system, or a distribution system, the system operator shall prepare an assessment of this request, evaluating whether the granting of the exemption meets all of the following criteria:

3.31. it does not cause discriminatory conditions for other customers in the system in respect of access to the transmission or distribution system;

3.32. it does not create competitive advantages for the owner of the electricity-consuming installation that is used for the provision of the demand response service compared to other owners of electricity-consuming installations that are used for the provision of the demand response service, or for the distribution system operator compared to other distribution system operators;

3.33. it does not affect system service costs;

3.34. it does not pose risks to ensuring the stable operating mode of the network of the relevant system operator;

3.35. it does not pose risks to the fulfilment of the technical requirements laid down for the network of the relevant system operator, including disturbances and breakdowns in such equipment and devices of other customers that are connected to the network;

3.36. it does not limit or significantly affect the capacity of the electricity system;

3.37. it does not negatively affect cross-border electricity trade;

3.38. it is not possible to fulfil the provisions of Regulation 2016/1388 by using reasonable technical solutions;

3.39. it generates benefits in accordance with the justification submitted by the customer in the system and the conducted cost-benefit analysis in conformity with the requirements of Article 49 of Regulation 2016/1388.

[*7 February 2018; 5 December 2019*]

3.4 The system operator shall, in its request to the regulator for granting an exemption from one or more provisions of Regulation 2016/1388 in respect of the connection of the electricity-consuming installation that is used for the provision of the demand response service, distribution installation connected to the transmission system, or distribution system, include an assessment, evaluating the criteria for granting the exemption laid down in Paragraph 3.3 of this Code.

[*7 February 2018*]

3.5 Upon receipt of a request from the owner or prospective owner of a high-voltage direct current system or direct current-connected power park module to grant an exemption from one or more provisions of Commission Regulation (EU) 2016/1447 of 26 August 2016 establishing a network code on requirements for grid connection of high-voltage direct current systems and direct current-connected power park modules (hereinafter – Regulation 2016/1447) in respect of the connection of a high-voltage direct current system or direct current-connected power park module, the system operator shall prepare an assessment of this request, evaluating whether the granting of the exemption meets all of the following criteria:

3.51. it does not cause discriminatory conditions for other customers in the system in respect of access to the transmission or distribution system;

3.52. it does not create competitive advantages for the owner of the high-voltage direct current system and direct current-connected power park module compared to other owners of high-voltage direct current systems or direct current-connected power park modules;

3.53. it does not affect system service costs;

3.54. it does not pose risks to ensuring the stable operating mode of the network of the relevant system operator;

3.55. it does not pose risks to the fulfilment of the technical requirements laid down for the network of the relevant system operator, including disturbances and breakdowns in such equipment and devices of other customers that are connected to the network;

3.56. it does not limit or significantly affect the capacity of the electricity system;

3.57. it does not negatively affect cross-border electricity trade;

3.58. it is not possible to fulfil the provisions of Regulation 2016/1447 by using reasonable technical solutions;

3.59. it generates benefits in accordance with the justification provided by the customer in the system and the conducted cost-benefit analysis in conformity with the requirements of Article 66 of Regulation 2016/1447.

[*7 February 2018; 5 December 2019*]

3.6 The system operator shall, in its request to the regulator for granting an exemption from one or more provisions of Regulation 2016/1447 in respect of the connection of the high-voltage direct current system or direct current-connected power park module, include an assessment, evaluating the criteria for granting the exemption laid down in Paragraph 3.5 of this Code.

[*7 February 2018*]

3.7 When installing the connection of a power-generating module, customers in the system shall comply with the requirements laid down in Annex 7 to this Code.

[*1 November 2018*]

3.8 When installing the connection of a high-voltage direct current system or direct current-connected power park module, customers in the system shall comply with the requirements laid down in Annex 10 to this Code. When installing the connection of a demand facility or distribution system, customers in the system shall comply with the requirements laid down in Annex 11 to this Code.

[*30 May 2019*]

4. The system participant has the following obligations:

4.1. upon request of the system operator, to provide information about the power generation and consumption forecasts of the electrical equipment, generation and load curves, and changes in the installed and available capacity of the electrical equipment;

4.2. to allow the persons authorised by the system operator to inspect the electrical equipment;

4.3. to ensure the management of its electrical equipment;

4.4. to fulfil the dispatch control orders;

4.5. to ensure the disconnection of the electrical equipment from the electricity system in case of a breakdown of electrical equipment or threats to the stable operating mode of the electricity system in conformity with the conditions agreed with the system operator;

4.6. to ensure the necessary installation and operation of communication, remote control, telemetry, and monitoring equipment, and also cover the installation costs;

4.7. to fulfil the requirements of the system operator for the installation of communication, technical measurement, and control equipment in order to ensure the stable operating mode of the electricity system;

4.8. upon written request of the system operator, to modernise, modify, or replace any communication or telemetry equipment already installed at the power station or substation;

4.9. to notify the system operator in writing about the modernisation, modification, or replacement of remote control equipment installed at the power station or substation if it does not correspond to the intended purpose;

4.10. to ensure the electricity supply for the communication, telemetry, remote signalling, and remote control equipment, so that they continue to operate for at least three hours after the electricity supply is interrupted at the connection point of the electrical equipment of the system participant;

4.11. to ensure the necessary communication lines and reservation thereof in the required volume for the communication with the communication, telemetry, remote control, and communication equipment of the electricity system participant;

4.12. to provide information about the technical capabilities to provide ancillary services in accordance with the procedures laid down by the system operator;

4.13. to ensure that the available capacity of each generating unit of the system participant does not exceed the nominal capacity of each generating unit laid down in the technical regulations issued by the system operator for the connection of generating equipment or the transformation of the connection of the existing generating equipment in any trading interval, as indicated by the electricity system participant in its application for the installation of the electricity system connection or transformation of the existing connection;

4.14. to enter into an agreement with the transmission system operator if market participants intend to provide system services and ancillary services to the transmission system operators of other countries before concluding a relevant contract, for the procedures for exchanging information necessary for the implementation of the contract and the activities to be performed by the transmission system operator;

4.15. to inform the system operator in writing about the modification of the electrical equipment by sending a description of the planned work and the technical parameters of the electrical equipment before and after the modification at least 60 days prior to the completion of the modification;

4.16. to implement the measures included in the restoration plan and defence plan;

4.17. if the electrical system participant establishes that the electrical equipment does not conform to the laid down technical requirements, the electrical system participant shall immediately inform the system operator thereof.

[*5 December 2019; 17 September 2020; 2 March 2023*]

**2.2. Inspection of the Electrical Equipment**

5. The system participant shall inspect the electrical equipment owned by the system participant that is connected to the electricity system of the system operator. The system operator has the right to request the system participant to inspect the electrical equipment owned by the system participant that is connected to the electricity system of the system operator. The system operator shall, to the extent possible, take into account the system participant’s opinion on the timing of the inspection of the electrical equipment.

[*5 December 2019*]

6. The inspections laid down in Annex 4 to this Code shall be conducted for new electrical equipment to be connected to the electricity system, modified electrical equipment, and an power-generating module that is considered to be an existing power-generating module within the meaning of Regulation 2016/631.

[*17 September 2020*]

6.1 The inspections laid down in Annex 5 to this Code shall be conducted for the electrical equipment of the final customer that is considered to be existing within the meaning of Regulation 2016/1388.

[*17 September 2020*]

6.2 The system operator shall publish on its website the procedures for conducting the inspections of electrical equipment, including the information that the system participant must provide in the application for the inspection of electrical equipment, the requirements for simulation mathematical models, and the preparation of compliance test reports. The time for submitting the application for the inspection of electrical equipment that is provided for in the procedures for conducting the inspections of electrical equipment may not exceed 45 working days before the planned inspection of the electrical equipment.

[*17 September 2020*]

6.3 If the Regulator has taken the decision to apply the requirements of Regulation 2016/631 after the modification of the power-generating module, in addition to the inspections specified in Annex 4 to this Code, the inspections referred to in Regulation 2016/631 shall also be conducted for the power-generating module to the extent that conforms to the requirements of Regulation 2016/631 that are applicable in accordance with the Regulator’s decision. If the Regulator has taken the decision to apply the requirements of Regulation 2016/1388 after the modification of a demand facility connected to the transmission system, an existing distribution installation connected to the transmission system, an existing distribution system, or an existing demand unit within a demand facility with a voltage level above 1 kV or within a closed distribution system with a voltage level above 1 kV, the inspections referred to in Regulation 2016/1388 shall be conducted to the extent that conforms to the requirements of Regulation 2016/1388 that are applicable in accordance with the Regulator’s decision.

[*17 September 2020*]

7. The system participant has the right to propose that the system operator to the system of which the electrical installations of the system participant are connected conducts the inspection of its electrical equipment. The system operator shall be obliged to allow conducting of such an inspection.

8. The system operator does not have the right to request the system participants to conduct the inspection of the electrical equipment more than once a year if the conformity of the electrical equipment to the laid down technical requirements has been confirmed, unless there are grounds to believe that the system participant fails to meet the laid down technical requirements.

[*17 September 2020*]

9. The system participant has the right to request the system operator to conduct the inspection of the electrical equipment of another system participant if there are grounds to believe that the system participant fails to meet the laid down technical requirements.

10. [17 September 2020]

11. The system operator has the right not to allow the inspection of the electrical equipment, change the inspection time, or request changes in the inspection procedures if the inspection of the electrical equipment has an adverse effect on the stable operating mode of the electricity system, the proper functioning of the electricity accounting meters at the connection point, or if a system service contract has not been concluded between the system operator and the system participant.

[*17 September 2020*]

12. When granting an authorisation for conducting the inspection of the electrical equipment, the system operator shall be obliged to prepare the system for the inspection before commencement of the inspection.

13. The system operator shall, at least five calendar days before the planned inspection of the electrical equipment, inform the system participants the electrical equipment of which is connected to the electricity system of the system operator about the inspection of the electrical equipment if it may have an adverse effect on their equipment. The transmission system operator shall, at least 15 calendar days before the planned inspection, inform the distribution system operator about the inspection organised within the transmission network by concurrently publishing the information on its website. The distribution system operator shall ensure that the system participants the electrical equipment of which is connected to the relevant distribution system are informed by publishing the information on its website.

[*5 December 2019*]

14. When conducting the inspection of the electrical equipment, the system participant and the system operator shall follow the technical requirements laid down by the manufacturer of the electrical equipment.

15. During the inspection of the electrical equipment, the system participant shall use the registration data of technical parameters recorded by the owner or user of the electrical equipment that were obtained by using certified measuring instruments and data loggers.

16. [17 September 2020]

17. [17 September 2020]

18. [2 March 2023]

19. [17 September 2020]

20. If after the inspection of the electrical equipment, the system operator establishes non-conformity of the electrical equipment with the laid down technical requirements, the electricity system participant shall, upon request of the system operator, provide evidence confirming the conformity or, in the absence of such evidence, conduct an extraordinary inspection within one month.

21. If it is established that the DSCGU does not conform with the laid down technical requirements, the electricity producer shall immediately inform the transmission system operator about the established fact, the planned measures, and the time limits for the elimination of non-conformities, and, once a month, inform the transmission system operator about the progress made in elimination of the non-conformities, and also conduct the necessary inspections confirming the conformity of the electrical equipment.

22. If the system operator has evidence of the non-conformity of the electrical equipment with the laid down technical requirements, and the system participant cannot provide documentary evidence to the contrary, and also the non-conformity significantly affects the stable operating mode of the system, the system participant shall, upon the order of the system operator, disconnect its electrical installation or part thereof that includes the non-conforming electrical equipment from the system until the moment the system participant submits documents confirming the conformity with the technical requirements or, together with the system operator, conducts the inspection of the electrical equipment to prove its conformity with the technical requirements.

[*5 December 2019*]

23. All expenses related to the organisation and conducting of the inspection of the electrical equipment shall be covered by the system participant who owns or possesses the electrical equipment to be inspected.

[*2 March 2023*]

24. The system operator shall not be responsible for the impact of the inspection of the electrical equipment of the system participant on the contractual obligations of the system participant with the trader, producer, or other market and system participants.

**2.3. Switching-on, Disconnection, and Connection of Electrical Equipment**

25. The system operator has the following obligations towards the system participant the electrical equipment of which is connected to the electricity system of the system operator:

25.1. within one month of receiving a switching-on programme for an electrical installation or part thereof, to notify the relevant system participant of the approval of its switching-on programme or request changes in the switching-on programme in order to ensure the stable operating mode of the electricity system;

25.2. to disconnect or allow the disconnection of the electrical installation of the system participant or part thereof from the electricity system upon a written request of the system participant, except for the cases, where the disconnection of the electrical installation of the system participant or part thereof poses a threat to the stable operating mode of the electricity system or the electricity supply of the electrical equipment of other system participants or customers. The disconnection may be for a specific period of time or permanent, removing the connection point completely.

26. The system participant has the following obligations:

26.1. to submit to the system operator a switching-on programme specifying the time and procedures for connecting the electrical installation or part thereof to the electricity system;

26.2. when connecting a new or reconstructed electrical installation to the electricity system, to submit in writing to the system operator the switching-on programme of the electrical equipment or part thereof and the electrical equipment inspection protocols at least three months before connection to the transmission system and at least two months before connection to the distribution system;

26.3. to cover the costs that are directly attributable to the disconnection or switching-off from the electricity system proposed by the system participant;

26.4. to agree with the system operator on the switching-off procedure for the electrical installation if the electrical installation of the system participant is to be permanently disconnected from the electricity system;

26.5. to disconnect or allow the disconnection of its electrical installation or part thereof from the electricity system upon the request of the system operator when satisfying a court decision, in the event of an emergency in the electricity system, in the event of a threat to the stable operation of the electricity system, or in accordance with an agreement with the system operator.

**2.4. Planning Development of the Electricity System**

27. System participants shall, upon request of the system operator, provide the system operator with short-term and long-term electricity consumption or generation forecasts in order to assess operating modes of the electricity system and plan development of the electricity system.

28. The system operator has the right to make corrections in the forecasts submitted by system participants if, according to the assessment of the system operator, the received forecast is inaccurate, informing the relevant system participant thereof.

29. If the system operator plans a reconstruction of the electricity system or construction of new facilities that directly affect the use of the system service or provision of the system service at a specific connection point, the system operator and the system participant shall agree on the necessary amendments to the system service contract.

30. When preparing the annual assessment report and the 10-year plan for the development of the electricity transmission system, the transmission system operator shall evaluate the static and dynamic stability of the system in various operating modes, taking into account the “n-1” criterion. Depending on the specific characteristics of the electricity system, the transmission system operator is entitled to employ a stricter safety criterion (“n-2” or higher) in individual cases.

**3. Safety of the Electricity System**

**3.1. Operating Modes of the Electricity System and Functions of the Transmission System Operator in Ensuring Them**

31. The transmission system operator shall provide information on its website about the technical requirements specified in contracts with transmission system operators of other countries that stipulate the common operating modes and safety criteria of the electricity systems of several countries.

[*30 May 2019*]

32. The transmission system operator shall plan the operating modes of the electricity system by using the “n-1” criterion. The transmission system operator shall determine the cases, where the “n-1” criterion can be ensured by using operational automations.

33. The transmission system operator is entitled to determine a stricter safety criteria (“n-2” and higher) if such criteria are necessary in a specific part of the network.

34. The electricity system shall have the following operating modes:

34.1. stable operating mode – where the frequency and voltage levels at the substation busbars conform to the requirements laid down in Annex 1 to this Code, the transmission line load does not exceed the maximum permissible values defined by the transmission system operator, the electrical equipment of the electricity system operates under normal operating modes, the ability of switching devices to disconnect conforms to the maximum possible short-circuit parameters of the network, the configuration of the electricity system ensures the localisation of a faulty circuit or electrical equipment with power switches, the static and dynamic stability conform to the safety requirements laid down in this Code, and the electricity system operates in parallel with electricity systems of other countries. The stable operating mode shall be divided into the following categories:

34.1.1. maximum safety mode – when all electrical equipment of the transmission and distribution systems is activated, and all DCGUs are available;

34.1.2. normal optimised operating mode – where, taking into account economic considerations and requirements of the “n-1” criterion, the system operator has disconnected a part of the electrical equipment of the electricity system in reserve and after a technological disturbance, the restoration of the electricity system is ensured to the normal optimised operating mode level within the time equivalent to the automation operating time, and this does not pose a threat to the stable operation of the electricity system;

34.1.3. planned repair mode – where, taking into account the “n-1” criterion, the electricity system participant performs planned repairs of the electrical equipment of the electricity system, and switching-off of the electrical equipment of one or more electricity system participants is possible, followed by the interruption of electricity supply for the electricity system participant;

34.2. unstable operating mode – where a possible technological disturbance may cause disturbances in the stable operation of the electricity system, cause the switching-off of generating units from the electricity system or part of the electricity system and the interruption of electricity supply for the electricity system participant;

34.3. emergency operating mode – where synchronous operation with the electricity systems of other countries is disturbed, or the electricity system is split into several separate parts due to an order of the transmission system operator or the activity of operational automation.

[*5 December 2019*]

35. The transmission system operator shall perform the following activities to maintain the safety of the electricity system:

35.1. monitor the operational status of the transmission system;

35.2. use and manage the transmission system, taking into account its technological limitations and technical requirements for the operation of electrical equipment;

35.3. ensure the safety of the electricity system during switching and repairs of the transmission system;

35.4. coordinate the activity of the distribution system operator in issues related to the joint operation of the transmission system and distribution system;

35.5. agree with the system participants on the operation of the electrical equipment of the transmission system in normal or emergency modes;

35.6. evaluate the possible risks in relation to the impact of technical and organisational measures on the operation of the electricity system;

35.7. organise the management of generation and loads for electricity producers and customers the electrical installations of which are connected to the electricity transmission system in accordance with the concluded system service contract;

35.8. determine possible restrictions on the operating modes of the system participant and assess the impact of these restrictions on the safety of the operation of the electricity system;

35.9. assess and monitor the adequacy of active and reactive power reserves and conformity thereof to the safety requirements of the system;

35.10. [2 March 2023];

35.11. manage the activities of electricity system participants in an operative manner to ensure, maintain, or restore the stable operating mode of the electricity system;

35.12. coordinate and manage the switching-off of the electrical installations of system participants that are connected to the transmission system, taking into account the sequence of electricity consumption restrictions and disconnections in the event of an emergency in the electricity system or in the event of a threat to the stable operating mode of the electricity system;

35.13. develop and, if necessary, update the restoration and defence plan;

35.14. select electricity producers with whom contracts are to be concluded, if necessary, for the use of generating units for autonomous start-up in case of total or partial blackout of the electricity system;

35.15. investigate and evaluate technological disturbances in the operation of the electricity system, take measures to prevent or mitigate the recurrence of technological disturbances. The system operator has the right to request from the system participant all the information necessary for the investigation and evaluation of operational disturbances in the operation of the electricity system;

35.16. upon request of the system participant, provide information about the operating modes of electrical equipment owned by the system operator during the operational disturbances of the electricity system;

35.17. decide on the suspension of market operations in accordance with Commission Regulation (EU) 2017/2196 establishing a network code on electricity emergency and restoration (hereinafter – Regulation 2017/2196) and the regulations regarding the suspension of market operations laid down in Annex 12 to this Code;

35.18. implement the measures included in the restoration plan and defence plan.

[*30 May 2019; 5 December 2019; 17 September 2020*]

**3.2. Safety Requirements for the Electricity System**

36. In order to ensure the electricity system frequency in conformity with the requirements laid down in Annex 1 to this Code, the transmission system operator shall perform the following activities:

36.1. to lay down the technical requirements for each DSCGU of the electricity producer according to its ability to automatically change the active power in response to changes in the electricity system frequency;

36.2. to agree with the electricity producer that has the most technically and commercially advantageous tender on the frequency regulation requirements for a specific DSCGU. When evaluating the tender of the electricity producer, the transmission system operator shall take into account the regulation range, regulation performance curves, droop, and other technical criteria of the DSCGU’s active power that affect frequency regulation capabilities;

36.3. to determine each year the load volumes connected to automatic load shedding system according to the frequency;

36.4. to conclude contracts with system participants for the provision of defence and restoration services, and ancillary service contracts for ensuring the regulation capacity product.

[*5 December 2019; 3 October 2024*]

37. When ensuring the provision of defence and restoration services, the following conditions shall be met:

37.1. the electrical installations to be used for the provision of defence and restoration services shall be located within the territorial areas of the licence of transmission system operator and be capable of operating in a synchronous network with the transmission system;

37.2. the defence service provider shall maintain capacity reserves for the safety of the electricity system in accordance with the requirements referred to in the defence plan. The amount of capacity reserves shall be determined by the transmission system operator according to the contracts concluded with transmission system operators of other countries, and the amount of capacity reserve shall be continuously available over the entire validity period of the contract;

37.3. the defence service provider shall ensure meeting the following minimum requirements:

37.3.1. the electrical installations used for maintaining the capacity reserves shall have a full capacity activation time not exceeding 15 minutes;

37.3.2. they shall be capable of ensuring adequate operation and proper maintenance of electrical installations in line with the needs of the transmission system;

37.4. the technical requirements applicable to the provision of defence service shall be laid down in the defence service contract;

37.5. the restoration service provider shall ensure compliance with the following minimum requirements:

37.5.1. the power-generating modules to be used for the provision of the restoration service shall be be located at a distance of not more than 150 km from Riga;

37.5.2. the power-generating module to be used for the provision of the restoration service shall be capable of ensuring the function of voltage regulation, and the voltage level of its connection point to the system shall be 330 kV;

37.5.3. the power-generating module to be used for the provision of the restoration service shall be capable of starting without receiving external voltage not later than within 60 minutes after receiving an order of dispatcher of the transmission system operator;

37.5.4. the transmission system operator shall have a possibility to re-connect upward voltage of the electricity system in accordance with the requirements referred to in the electricity system restoration plan;

37.6. the technical requirements applicable to the provision of restoration service shall be laid down in the restoration service contract.

[*5 December 2019*]

37.1 The transmission system operator shall publish on its website sample contracts for the provision of defence and restoration services.

[*5 December 2019*]

37.2 For the purpose of checking on conformity of capabilities of the power-generating modules used by the restoration service provider and defence service provider, the following testing shall be conducted:

37.21. the restoration service provider shall test each year the capability of its power-generating module to meet the requirements laid down in Sub-paragraphs 37.1, 37.5, and 37.6 of this Code, in conformity with the restoration plan. The testing shall be conducted by following the requirements laid down in Article 45(5) of Regulation 2016/631;

37.22. the defence service provider shall, at least every four years, test the capability of its power-generating module which is used for ensuring implementation of automatic control scheme for excessively low or excessively high frequencies to meet the measures laid down in Sub-paragraphs 37.1, 37.3.2, and 37.4 of this Code, in conformity with the defence plan;

37.23. the transmission system operator shall continuously monitor the capability of the power-generating module of the defence service provider which is used for the provision of capacity reserves to meet the provisions of Sub-paragraphs 37.1, 37.3.1, and 37.4 of this Code, in conformity with the defnce plan, using information about the modes and capacity reserves of power plants of the defence service provider.

[*17 September 2020*]

37.3 For the purpose of checking on conformity of equipment used by the transmission system operator and distribution system operator for automatic demand disconnection at a low frequency, the following testing shall be conducted:

37.31. the transmission system operator shall, at least once every four years, test the equipment possessed and operated by the transmission system operator that ensures the automatic demand disconnection based on frequency, in conformity with that laid down in the defence plan;

37.32. the distribution system operator shall, at least once every four years, test the equipment owned by the distribution system operator that ensures the automatic demand disconnection based on frequency, in conformity with that laid down in the defence plan. The testing shall be conducted by following the requirements of Article 37(6) of Regulation 2016/1388. For the purpose of checking on a relevant measure laid down in the defence plan, the distribution system operator shall, twice a year, send information to the transmission system operator about the connections connected to the equipment that ensure automatic demand disconnection based on frequency.

[*17 September 2020*]

37.4 The transmission system operator shall determine and publish on its website the procedures for testing the capabilities of defence and restoration service providers, the distribution system operator, and the transmission system operator laid down in Paragraphs 37.2 and 37.3 of this Code upon consultation with the involved system participants.

[*17 September 2020*]

38. The transmission system operator shall ensure the following allowable voltage level ranges in the transmission system in the stable operating mode:

38.1. in the 110 kV network: 99–122.98 kV;

38.2. in the 330 kV network: 297–362.01 kV.

[*30 May 2019*]

39. The transmission system operator shall ensure the operation of electrical equipment within the transmission system, so that regulation of voltage levels and reactive power balance can be conducted, following the “n-1” criterion.

40. The transmission system operator shall ensure the management of regulating equipment of voltage levels and reactive capacity of the transmission system.

41. The transmission system operator shall regulate voltage levels of the the transmission system by using the reactive power output or input capabilities of the DSCGU, tap regulation of transformers and auto transformers, shunt reactors, capacitor banks, and also by disconnecting electricity transmission lines in reserve according to the “n-1” criterion. In emergency operating modes of the electricity system, operational automations shall also be used for voltage regulation.

42. If it is impossible in any part of the system to ensure the voltage level laid down in Annex 1 to this Code, the system operator shall take all possible measures, including disconnecting equipment of system participants in the volume of changes in capacity flows that are necessary to restore the voltage to an acceptable level.

43. The transmission system operator shall ensure the following in new substations of the transmission system or substations of the transmission system to be reconstructed:

43.1. each connection shall have its own switching device;

43.2. 330 kV circuit breakers shall have synchrocheck;

43.3. the primary scheme shall be maintained in the stable operating mode in a substation with four or more connections of electricity transmission lines in the following cases:

43.3.1. in the event of a failure of operation of any circuit breaker, not more than two connections of electricity transmission lines shall be disconnected;

43.3.2. in the event of disconnection of one busbar system, electricity transit shall not be interrupted;

43.4. switching an electricity transmission line in the stable operating mode shall be performed with no more than two circuit breakers per connection;

43.5. in the event of a failure of a circuit breaker of any substation with a normal operating scheme, generating units with a total installed capacity exceeding 300 MW shall not be disconnected, and the stable operating mode of the electricity system shall be maintained.

44. For the purpose of ensuring the stable operating mode of the electricity system, the transmission system operator shall control the following:

44.1. the required voltage and short-circuit capacity levels for the selective operation of relay protection and automation when generating units operate at a minimum configuration;

44.2. the volumes of transmitted electricity supplies to electricity system participants from the perspective of static and dynamic stability and, if necessary, modify them;

44.3. so that the operation of generating units with minimal loads or in a partial excitation mode does not reduce the reserves of static and dynamic stability of the electricity system below specific values.

45. The system operator has the right to give a dispatch control order to the electricity system participant to disconnect an electrical installation of a specific electricity system participant or part thereof from the electricity system in the event of an emergency in the electricity system or when the stable operation of the system is threatened, and the system operator shall be obliged to give a dispatch control order to the system participant to connect to the electricity system its electrical installation or part thereof at the end of the emergency in the electricity system or after restoration of the stable operation of the system.

46. The system participant shall be obliged to:

46.1. reduce the load or power generation to zero level by disconnecting the electrical installation or part thereof from the electricity system if it is requested by the transmission system operator or the distribution system operator upon request of the transmission operator in the event of an emergency in the electricity system or in the event of a threat to the stable operation of the electricity system;

46.2. disconnect or allow the system operator to disconnect the electrical installation or part thereof if it poses a threat to human safety, electrical equipment of other electricity system participants or the system operator, or the stable operating mode of the electricity system is at risk;

46.3. activate the frequency sensitive mode (FSM) or frequency restoration control for an operational type C or D power-generating module to the extent that is technically feasible and does not pose a threat to the safe operation of other nodes and equipment if it is requested by the transmission system operator or the distribution system operator upon request of the transmission operator in the event of an emergency in the electricity system or in the event of a threat to the stable operation of the electricity system.

[*5 December 2019; 2 March 2023*]

47. The system operator and the system participant the electrical installations of which are connected to the electricity system of the system operator shall mutually exchange contact information about the operational personnel and personnel responsible for the operational management of equipment and the provision of exchange of technical information. The contact information shall include the given name, surname, position, telephone number, fax number, and electronic mail address of the responsible person.

**3.3. Operational Procedures of the Electricity System**

48. The transmission system operator shall draw up an operational schedule of the electricity system by taking into account the following:

48.1. the consumption schedule forecast submitted by system participants and traders, available generating units, schedules of generating units, volumes of electricity supplies from other countries, and also throughput of the transmission system and distribution system;

48.2. the safety of power-generating and transmission;

48.3. the planned repair schedules of electricity system equipment or other capacity transmission limitations determined by the transmission system operator, transmission system operators of other countries, and distribution system operators.

49. The transmission system operator shall conduct the annual planning for the operating modes of the electricity system by taking into account the planned annual electricity consumption of the electricity system, the planned capacity and power generation of generating units, and also the forecasted volumes of electricity supplies from other countries. The transmission system operator shall prepare the annual plan for operating modes for the next calendar year not later than 30 days before the beginning of the next year.

50. The transmission system operator shall prepare a plan for operating modes of the electricity system for the next month not later than three days before the beginning of the next calendar month, including in the plan the following:

50.1. the electricity consumption of the electricity system by imbalance settlement periods for Wednesday and Sunday of each week;

50.2. the DSCGU capacities, their minimum loads, and repair schedules for Wednesday and Sunday of each week of the month;

50.3. the repair schedule for the transmission system equipment;

50.4. the electricity consumption of the electricity system for each day of the month.

[*2 March 2023*]

51. The transmission system operator shall prepare a plan for the operational operating mode of the electricity system for each next week not later than by Friday of the previous week, including in the plan the following:

51.1. the composition of DSCGU equipment, the active power and power generation schedule by days and hours;

51.2. the electricity consumption of the electricity system by days and hours;

51.3. the weekly actuation schedule for water reservoirs of the Daugava cascade hydroelectric power station with a breakdown by days and hours;

51.4. all types of active power reserves of DSCGU.

52. The transmission system operator shall prepare a plan for operating modes of the electricity system for the next 24 hours by imbalance settlement periods by the deadline laid down in the system use contract concluded with the electricity market participant, and the plan shall include information about the following:

52.1. the composition of DSCGU;

52.2. the balance of generating capacity and consumption capacity;

52.3. the pool levels of water reservoirs of the Daugava cascade hydroelectric power station;

52.4. the volumes of electricity imports and exports.

[*2 March 2023*]

53. The procedures for exchanging information between the system operator and the system participant regarding technical changes in the electricity system that may affect the operation of its electrical equipment, and the operational ownership of electrical equipment shall be determined in the system service contract.

54. In order to ensure the stable operating mode of the electricity system, the electricity producer, without posing a threat to human safety or causing equipment damage, shall:

54.1. ensure active power generation in conformity with the load curve agreed upon with the system operator within a specific period;

54.2. regulate the voltage level according to the range laid down by the system operator, using the absorption and generation capabilities of reactive power.

55. The electricity producer shall not be responsible for deviations in the generation of the DSCGU’s active power from the generation schedule laid down by the system operator, and it has the right not to fulfil the voltage schedule laid down by the system operator in cases related to ensuring the stable operating mode of the electricity system if:

55.1. the DSCGU is connected to the distribution system and follows the dispatch control instructions of the transmission system operator;

55.2. the DSCGU participates in frequency regulation or its operation is affected by the operational activity or mode automation of the electricity system.

56. The electricity producer does not have the right to connect or disconnect the DSCGU from the network without an authorisation of the relevant system operator, except for the cases, where this occurs due to operational activities or mode automation, a threat is posed to human safety, or equipment damage is caused.

57. The electricity producer shall inform the system operator about the commencement of the DSCGU operation according to the laid down load curve, except for the cases, where the relevant DSCGU operation is controlled remotely by the system operator.

58. The transmission system operator and the distribution system operator shall ensure exchange of information about activities and conditions that may affect the safety of the electricity system.

59. The transmission system operator may provide instructions to the distribution system operator or system participant the electrical installations of which are connected to the network of the distribution system operator, to commence or discontinue the operation of reactive power compensation equipment in order to ensure the stable operating mode of the system if the transmission system operator and the relevant distribution system operator or system participant have agreed on this in advance.

[*5 December 2019*]

60. The transmission system operator has the right to request information from the distribution system operator about the operating modes of any system participant connected to its network.

61. If, in accordance with the “n-1” criterion, it is not possible to ensure the stable operating mode in some part of the electricity system, the system operator may purchase electricity from generating units that are located in such part of the electricity system, where the stable operating mode is at risk.

**3.4. Capacities of Cross-border Interconnections, Congestion Management, and Overload Prevention**

62. The transmission system operator shall determine the throughput of cross-border interconnections as follows:

62.1. the maximum throughput of cross-border transmission networks shall be calculated for the 330 kV transmission network, taking into account the criteria of thermal withstand, static and dynamic stability. The calculation procedures, agreed upon by the transmission system operators of the involved countries, shall be published on the website of the transmission system operator;

62.2. the calculation of the safety reserve for the throughput that is necessary to ensure exchange of emergency reserve between the transmission system operators of the countries in case of unexpected frequency deviations or disconnections of electrical network elements, and to take into account the capacity flow deviations between the planned and actual capacity flow in the cross-border section. The safety reserve for the throughput shall be determined in conformity with the methodology laid down in the mutual contracts with the transmission system operators of other countries;

62.3. the maximum available throughput shall be the maximum throughput that can be used for cross-border electricity trading operations and transit. The maximum available throughput shall be calculated by subtracting the safety reserve for the throughput from the maximum throughput;

62.4. the allocated throughput shall be the throughput assigned by the transmission system operator to an electricity trader for conducting trading operations or reserved by it for specific electricity trading operations;

62.5. the available throughput shall be the throughput that is available for possible electricity trading operations. The available throughput shall be calculated by subtracting the allocated throughput from the maximum available throughput.

[*30 May 2019*]

63. For the purpose of preventing capacity congestions in cross-border connections during the planning period, direct and indirect auctions shall be organised. The transmission system operator shall, together with the transmission system operators of the involved countries, organise the direct auction of available throughputs or delegate it to another legal person. The indirect auction of throughputs shall be organised by the electricity exchange. The electricity exchange shall register and reject trading operations in accordance with the exchange by-laws.

64. In cases where electricity flow exceeds the maximum throughput in cross-border interconnections, the transmission system operator shall carry out congestion management activities agreed upon with the transmission system operators of the involved countries, ensuring that physical electricity flows in cross-border interconnections conform to the safety requirements for the transmission network. The transmission system operator shall cover the costs incurred by carrying out congestion management activities.

65. The transmission system operator has the right to refuse a cross-border trading operation if the additional physical energy flows that would result from conducting this trading operation could lead to a situation where the transmission system operator cannot guarantee secure operation of the electricity system.

66. The transmission system operator shall ensure calculation of cross-border interconnection capacities, congestion management, and overload prevention in accordance with the conditions contained in the contracts that are concluded between the transmission system operators of the involved countries in line with the principles laid down in the European Union legal acts, and that are published on the website of the transmission system operator.

[*2 March 2023*]

67. [2 March 2023]

68. The conditions of the contracts concluded between the transmission system operators, as specified in Paragraph 66 of this Code, shall be applicable to the calculation of cross-border interconnection capacities, congestion management, and overload prevention, unless the regulatory authorities of the involved countries have requested to amend the conditions for the calculation of cross-border interconnection capacities and overload management laid down in the abovementioned contracts, including those regarding capacity allocation.

**3.5. Actions of the Transmission System Operator in the Event of Emergencies in the Electricity System**

69. The system operator shall ensure its network for the operation in the event of emergencies in the electricity system by carrying out the following activities:

69.1. to alert the system participants to an emergency in the electricity system that may result in the energy crisis defined in laws and regulations;

69.2. to expedite the activation of electrical equipment under repair for reserve or operation;

69.3. to suspend the disconnection of electrical equipment for planned repairs, except for the emergency repairs;

69.4. to maximise the safety of the electricity supply scheme by activating in operation the electrical equipment that is in reserve or has been disconnected for observations;

69.5. to perform switching in houseload supply schemes of the generating unit in accordance with the restoration plan in order to ensure that generating units are able to operate only with houseload or island.

[*5 December 2019*]

70. If the active capacity generation or supply resources are insufficient, the transmission system operator has the right to do the following in order to ensure the stable operating mode of the system:

70.1. to increase generation capacity by using the DSCGU’s capacity reserve or activating in operation the transmission lines that are in reserve;

70.2. to give a dispatch control order to the distribution system operator to limit or disconnect the loads of the system participants connected to its distribution system;

70.3. to instruct system participants the electrical installations of which are connected to the transmission system, to take the necessary measures in order to immediately reduce the load or disconnect their electrical equipment.

[*5 December 2019*]

71. The transmission system operator shall take the necessary technical and organisational measures in order to maintain or restore the stable operating mode of the electricity system or part thereof in the event of an emergency in the electricity system or after a technological disturbance that has caused a significant reduction in load or generation and may result in interruptions or limitations of electricity supply in the electricity system or parts thereof.

72. The system operator shall collect and evaluate the information about technological disturbances that pose significant threats to the stable operating mode of the electricity system and shall take measures to exclude or mitigate the occurrence of such technological disturbances. The system operator has the right to request from the system participants all the information necessary for the evaluation of disturbances in the operation of the electricity system.

73. The system operator shall, upon request of the system participant, provide information about the operation of electrical equipment owned by the system operator during significant disturbances in the operation of the electricity system.

**4. Balancing of the Electricity System and Electricity Trade**

[14 December 2017]

74. [14 December 2017]

75. [14 December 2017]

76. [14 December 2017]

77. [14 December 2017]

78. [14 December 2017]

79. [14 December 2017]

80. [14 December 2017]

81. [14 December 2017]

82. [14 December 2017]

83. [14 December 2017]

84. [14 December 2017]

85. [14 December 2017]

86. [14 December 2017]

87. [14 December 2017]

88. [14 December 2017]

89. [14 December 2017]

90. [14 December 2017]

**4.1 Balancing of the Electricity System**

[*14 December 2017*]

**4.11. Provision of the Balancing Service**

[*14 December 2017*]

90.1 The transmission system operator shall perform balancing within a coordinated balancing area in cooperation with other transmission system operators of the coordinated balancing area in accordance with the concluded cooperation contracts. If the transmission system operator organises the balancing market in accordance with Article 20(6) or Article 21(6) of Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (hereinafter – Regulation 2017/2195), balancing shall be performed within the control zone of the transmission system operator. The transmission system operator shall notify balancing service recipients and regulation service providers of the balancing performed within the control zone in accordance with the procedures laid down in the balancing contract and ancillary service contract not later than one working day before the start of the time unit of the relevant balancing market, concurrently publishing this information on the website of the transmission system operator.

[*3 October 2024*]

90.2 The transmission system operator shall develop balancing market rules, stipulating the procedures for providing the regulation service and the requirements to be followed by balancing market participants in their operations within the balancing energy market. If balancing is performed within a coordinated balancing area, the transmission system operator shall develop the balancing market rules in cooperation with other transmission system operators of the coordinated balancing area. When providing the regulation service, market participants and system operators shall follow the requirements laid down in Annex 8 to this Code.

[*3 October 2024*]

90.3 The transmission system operator shall publish on its website the balancing market rules referred to in Paragraph 90.2 of this Code. The transmission system operator shall notify the planned amendments to the balancing market rules not later than one month before entry into force of the planned amendments.

[*14 December 2017; 30 May 2019*]

90.4 Prior to commencing electricity trading operation, a trader shall conclude a system use contract with the transmission system operator. The transmission system operator shall publish on its website a common form of the system use contract.

[*14 December 2017; 30 May 2019*]

90.5 In order to commence the provision of balancing service to another trader, the trader shall conclude a balancing contract with the transmission system operator. The transmission system operator shall publish on its website a common form of the balancing contract.

[*14 December 2017; 30 May 2019*]

90.6 The transmission system operator shall publish and regularly update the information on its website about the traders that have a valid system use contract and the balancing service providers that are entitled to provide the balancing service to another trader.

[*14 December 2017; 30 May 2019*]

90.7 The transmission system operator shall determine the imbalance area of the balancing service recipient based on the information available to the transmission system operator and provided by the distribution system operators and the balancing service recipient about the commercial accounting points of the balancing service recipient or the commercial accounting points of customers and producers for whom the balancing service recipient provides the balancing service, and the commercial accounting points of customers and producers whose trader is provided with the balancing service by the balancing service recipient. Each commercial accounting point shall only be included in one imbalance area, depending on the direction of electricity flow. The balancing service provider shall inform the transmission system operator of any changes in relation to the traders included in the imbalance area of the balancing service provider in accordance with the procedures laid down in the balancing contract.

[*30 May 2019*]

90.8 A trader who is not a balancing service provider for another trader but who provides the balancing service to a customer or producer shall conclude the balancing service contract with the balancing service provider. Only one balancing service provider shall provide the trader with the balancing service within one settlement period.

[*14 December 2017*]

90.9 A trader that provides the balancing service but does not have a valid balancing or balancing service contract shall be provided with the balancing service by the transmission system operator in accordance with the procedures laid down in the system use contract.

[*14 December 2017*]

90.10 A trader is entitled to change the balancing service provider on the first day of each calendar month if the new balancing service provider selected by the trader has notified the transmission system operator in writing of the commencement of the provision of the balancing service by the ninth day of the previous month.

[*14 December 2017; 3 October 2024*]

90.11 The new balancing service provider may withdraw the notification referred to in Paragraph 90.10 of this Code by the fourth day of the previous month.

[*14 December 2017; 3 October 2024*]

90.12 The transmission system operator shall inform the trader’s previous and new balancing service providers regarding the change of the trader’s balancing service provider by the twenty-sixth day of the previous month.

[*14 December 2017; 3 October 2024*]

90.13 If the balancing contract concluded between the transmission system operator and the balancing service provider has been terminated, the transmission system operator shall inform the traders thereof for whom this balancing service provider ensures the provision of the balancing service not later than within five working days from the day of termination of the contract.

[*14 December 2017*]

90.14 A customer or producer who has chosen the transmission system operator as its balancing service provider shall conclude the balancing service contract with the transmission system operator.

[*14 December 2017*]

**4.12. Determination of Imbalance, Imbalance Price Fixing, and Imbalance Settlements**

[*14 December 2017*]

90.15 The balancing service recipient shall be financially responsible for the imbalance created within its imbalance area and settle payments for it with the transmission system operator in accordance with the procedures and time limits laid down in the balancing contract and the balancing service contract, following the provisions of this Chapter.

[*30 May 2019*]

90.16 The fee for the provision of the balancing service during the settlement period shall be calculated as follows:

, where

Mbps – fee for the provision of the balancing service during the settlement period (EUR);

t – imbalance settlement period;

T – number of imbalance settlement periods within the settlement period;

 – imbalance fee during the imbalance settlement period t (EUR);

Ma – administration fee for the imbalance settlements during the settlement period (EUR).

[*14 December 2017; 2 March 2023*]

90.17 The imbalance fee for the imbalance settlement period t shall be calculated as follows:

, where

 – imbalance of the balancing service recipient during the imbalance settlement period t (MWh);

 – imbalance price during the imbalance settlement period t (EUR/MWh).

[*14 December 2017; 2 March 2023*]

90.18 The imbalance of the balancing service recipient in megawatt-hours [MWh] with an accuracy of up to three decimal places during imbalance settlement period t shall be calculated as follows:

, where

 – the quantity of electricity allocated to the balancing service recipient during the imbalance settlement period t (MWh);

 – the final position of the balancing service recipient during the imbalance settlement period t (MWh) that is calculated by taking into account the information provided by the balancing service recipient in accordance with the provisions of Annex 9 to this Code.

[*30 May 2019; 2 March 2023*]

90.19 The imbalance fee during the imbalance settlement period shall be applied by taking into account the following conditions:

90.191. when calculating the imbalance fee for the balancing service recipient, the quantity of electricity allocated and the final position shall be determined by applying a minus sign to the amount of electricity consumption and a plus sign to the volume of electricity produced;

90.192. balancing service recipients, for whom the quantity of electricity allocated during the imbalance settlement period has been less than the final position, shall purchase the missing electricity from the transmission system operator during the imbalance settlement period;

90.193. balancing service recipients, for whom the quantity of electricity allocated during the imbalance settlement period has been higher than the final position, shall sell the excess electricity to the transmission system operator during the imbalance settlement period.

[*14 December 2017; 30 May 2019; 2 March 2023*]

90.20 The quantity of electricity allocated to the balancing service recipient shall be determined based on the information available to the transmission system operator and provided by the distribution system operators about the commercial accounting data of electricity within the imbalance area of the balancing service recipient and the information about the information provided by the distribution system operators about the total corrections made for the previous settlement periods in accordance with the procedures laid down in Paragraph 90.22 of this Code.

[*14 December 2017*]

90.21 The distribution system operators shall electronically submit to the transmission system operator the summary data of electricity customers and producers for each imbalance settlement period broken down by traders in accordance with the following procedures:

90.211. by Wednesday of each week – the operational commercial accounting data of electricity for the previous week which allow to obtain information about the previous week;

90.212. by the eight day of each month – the commercial accounting data of electricity for the previous month.

[*2 March 2023*]

90.22 After the submission of commercial accounting data of electricity to the transmission system operator, the distribution system operators shall make corrections to the submitted commercial accounting data of electricity by following the conditions and time limits for the correction of commercial accounting data of electricity contained in the electricity trading and use rules. The distribution system operators shall inform the transmission system operator about the total corrections in previous settlement periods in the commercial accounting data of electricity submitted to the transmission system operator concurrently with the regular submission of the commercial accounting data of electricity within the time limit laid down in Paragraph 90.21 of this Code.

[*14 December 2017*]

90.23The imbalance price shall be calculated as follows:

90.231. if during the imbalance settlement period t, the balancing was performed within the coordinated balancing area and only normal activations for upward regulation were carried out:

, where

 – regulation electricity price for upward regulation for the imbalance settlement period t determined in accordance with the balancing market rules referred to in Paragraph 90.2 of this Code (EUR/MWh);

 – neutrality component, calculated as follows:

, where

 – the difference between the revenue and expenditure of the transmission system operators within the coordinated balancing area for the imbalance settlement period t, arising to the transmission system operators from balancing activities during a specific imbalance settlement period t (EUR);

 – the difference between the revenue and expenditure of the transmission system operators within the coordinated balancing area for the imbalance settlement period t, arising to the transmission system operators from the purchase and sale of balancing electricity from the open balancing service provider selected by the transmission system operators within the coordinated balancing area (EUR);

 – imbalance created by the balancing service recipient during a specific imbalance settlement period t (MWh) that is used to determine the total imbalance caused by balancing service recipients. The total imbalance caused by the balancing service recipients shall be equal to the net imbalance of the coordinated balancing area that consists of the net imbalance of each electricity system forming the coordinated balancing area;

 – imbalance caused by the balancing service recipient during a specific imbalance settlement period t (MWh) where over-activation occurred. Over-activation is a situation during the imbalance settlement period t, where unexpected changes have occurred in the quantity of electricity allocated to balancing service recipients, as a result of which the initial activations of regulation commitments were performed opposite to the imbalance direction determined for the coordinated balancing area in the imbalance settlement period. If no over-activation has occurred, the calculation component shall be 0;

 – regulation electricity price used during the imbalance settlement period t that has been applied in accordance with the conditions of Sub-paragraph 90.231, 90.232, 90.233, or 90.234 of this Code (EUR/MWh);

N – number of balancing service recipients within the coordinated balancing area;

n – a specific balancing service recipient;

T – total number of imbalance settlement periods within the accounting period;

90.232. if during the imbalance settlement period t the balancing was performed within the coordinated balancing area and only normal activations for downward regulation were carried out:

, where

 – regulation electricity price for downward regulation for the imbalance settlement period t calculated in accordance with the balancing market rules referred to in Paragraph 90.2 of this Code (EUR/MWh);

90.233. if during the imbalance settlement period t the balancing was performed within the coordinated balancing area and normal activations for both upward and downward regulation were carried out, the imbalance price shall be calculated as follows:

90.233.1. for the imbalance settlement period t, when there was an electricity deficit within the coordinated balancing area:



90.233.2. for the imbalance settlement period t, when there was an electricity surplus within the coordinated balancing area:



90.234. if during the imbalance settlement period t the balancing was performed within the coordinated balancing area and no activations were carried out, the value of avoided activation shall be used instead of the regulation electricity price, and this value shall be determined based on whether there was an electricity deficit or surplus within the coordinated balancing area, as follows:

90.234.1. for the imbalance settlement period t, when there was an electricity deficit within the coordinated balancing area:

, where

 – the lowest price of upward regulation bids submitted by regulation service providers within the coordinated balancing area that are available during the imbalance settlement period t (EUR/MWh). If no upward regulation bids submitted by regulation service providers within the coordinated balancing area were available during the imbalance settlement period t, the value of avoided activation shall be 0 (EUR/MWh);

90.234.2. for the imbalance settlement period t, when there was an electricity surplus within the coordinated balancing area:

, where

 – the highest price of downward regulation bids submitted by regulation service providers within the coordinated balancing area that are available during the imbalance settlement period t (EUR/MWh). If no downward regulation bids submitted by regulation service providers within the coordinated balancing area were available during the imbalance settlement period t, the value of avoided activation shall be 0 (EUR/MWh).

90.235. if during the imbalance settlement period t, the balancing was performed within the control zone and the request for normal and normal local activation was only made for upward regulation:

, where

 – regulation electricity price for upward regulation for the imbalance settlement period t determined according to the balancing market rules in accordance with Paragraphs 21.1 and 21.2 of Annex 8 to this Code in the market time units  that fall within the imbalance settlement period t;

 – neutrality component, calculated as follows:

, where

 – the difference between the revenue and expenditure of the transmission system operator for the imbalance settlement period t, arising to the transmission system operator from settlements with the regulation service provider for activated regulation product bids during a specific imbalance settlement period t (EUR);

 – the difference between the revenue and expenditure of the transmission system operator in the market time unit  , resulting from settlements with the transmission system operator of another country for the purchased and sold regulation energy within the relevant control zone;

 – the difference between the revenue and expenditure of the transmission system operator in the market time unit  , arising to the transmission system operator from settlements with the transmission system operator of another country for the quantity of electricity in accordance with Article 51(1) of Regulation 2017/2195, where corrections, if calculated, are applied to the settlement period in which the respective correction was received;

 – imbalance caused by the balancing service recipient during a specific imbalance settlement period t (MWh) where over-activation occurred. Over-activation is a situation during the imbalance settlement period t, where unexpected changes have occurred in the quantity of electricity allocated to balancing service recipients, as a result of which the initial regulation requests were made opposite to the imbalance direction determined for the control zone in the imbalance settlement period. If no over-activation has occurred, the calculation component shall be 0;

 – regulation electricity price used during the imbalance settlement period t that has been applied in accordance with the conditions of Sub-paragraph 90.235, 90.236, 90.237, or 90.238 of this Code (EUR/MWh);

N – number of balancing service recipients within the control zone;

n – a specific balancing service recipient;

T – total number of imbalance settlement periods within the accounting period;

tb – time market unit;

TB – total number of time market units within the accounting period;

90.236. if during the imbalance settlement period t the balancing was performed within the control zone and the request for normal and normal local activation was only made for downward regulation:

, where

 – regulation electricity price for downward regulation for the imbalance settlement period t determined according to the balancing market rules in accordance with Paragraphs 21.1 and 21.2 of Annex 8 to this Code in the market time units  that fall within the imbalance settlement period t.

90.237. if during the imbalance settlement period t the balancing was performed within the control zone and the request for normal and normal local activation was made for both upward and downward regulation, the imbalance price shall be calculated as follows:

90.237.1. for the imbalance settlement period t, when there was an electricity deficit within the control zone:



90.237.2. for the imbalance settlement period t, when there was an electricity surplus within the control zone:



90.238. if during the imbalance settlement period t, no request for normal or normal local activation was made within the control zone, the value of avoided activation shall be used instead of the regulation electricity price, and this value shall be determined based on whether there was an electricity deficit or surplus within the control zone, as follows:

90.238.1. for the imbalance settlement period t, when there was an electricity deficit within the control zone:

, where

 – the average price of the lowest-priced upward regulation bids submitted by regulation service providers within the control zone that are available for each balancing product in each market time unit  during the imbalance settlement period (EUR/ MWh). If no bids are available for some regulation product in a market time unit , it shall not be included in the calculation of the average price. If no upward regulation bids submitted by regulation service providers within the control zone were available during the imbalance settlement period t, the value of avoided activation shall be 0 (EUR/MWh);

90.238.2. for the imbalance settlement period t, when there was an electricity surplus within the control zone:

, where

 – the average price of the highest-priced downward regulation bids submitted by regulation service providers within the control zone that are available for each balancing product in each market time unit  during the imbalance settlement period (EUR/ MWh). If no bids are available for some regulation product in a market time unit , it shall not be included in the calculation of the average price. If no downward regulation bids submitted by regulation service providers within the control zone were available during the imbalance settlement period t, the value of avoided activation shall be 0 (EUR/MWh).

[*3 October 2024*]

90.24The transmission system operator shall publish the calculated imbalance price and neutrality component for the imbalance settlement period on its website or another website specified on the website of the transmission system operator not later than on the fifth working day of the following month.

[*3 October 2024*]

90.25 [16 January 2025]

**4.13. Security for the Fulfilment of Contractual Obligations**

[*2 March 2023*]

90.26In order to secure payments for the balancing service, the transmission system operator is entitled to request the balancing service recipient to secure its contractual obligations if the balancing service recipient does not have a granted credit rating that meets to the criteria laid down in Paragraph 90.27 of this Code.

[*2 March 2023*]

90.27The credit rating of the balancing service recipient shall be deemed appropriate if it meets at least one of the following criteria:

90.271. Standard & Poor’s long-term rating is BBB- or higher;

90.272. Fitch Ratings long-term rating is BBB- or higher;

90.273. Moody’s long-term rating is Baa3 or higher.

[*2 March 2023*]

90.28 A balancing service recipient that has a granted credit rating shall be obliged to immediately inform the transmission system operator of any changes in the credit rating of the balancing service recipient, and the transmission system operator is entitled to request the balancing service recipient to provide updated information about the credit rating of the balancing service recipient.

[*2 March 2023*]

90.29 The transmission system operator is entitled to request the balancing service recipient that has a granted credit rating to submit contract a security for fulfilment of obligations to cover the payment claims arising from the contract if:

90.291. the credit rating of the balancing service recipient no longer meets the criteria laid down in Paragraph 90.27 of this Code;

90.292. the transmission system operator establishes an increased risk due to the debtor obligations of the balancing service recipient exceeding the minimum amount of the security for the fulfilment of obligations;

90.293. the transmission system operator establishes that the balancing service recipient is unable to cover its debtor obligations fully or partly, including due to a change in and increase of risks related to the solvency of the balancing service recipient;

90.294. insolvency or liquidation proceedings have been initiated against the balancing service recipient;

90.295. the balancing service recipient violates the requirements laid down in the balancing contract or balancing service contract;

90.296. the balancing service recipient has delayed payments laid down in the balancing contract or balancing service contract twice over 12 months.

[*2 March 2023*]

90.30 If the balancing service recipient does not agree with the findings of the transmission system operator in accordance with Paragraph 90.29 of this Code or non-conformity of the credit rating of the balancing service recipient, the balance service recipient may submit appropriate evidence within five working days, so that the transmission system operator can objectively assess the creditworthiness of the balancing service recipient.

[*2 March 2023*]

90.31 The balancing service recipient shall secure fulfilment of contractual obligations by using one or both of the following types of the security for the fulfilment of liabilities – a security deposit or a guarantee of the financial service provider.

[*2 March 2023*]

90.32 The balancing service recipient shall provide the security for the fulfilment of liabilities to the transmission system operator in accordance with the procedures laid down in the balancing contract or the balancing service contract.

[*2 March 2023*]

90.33 Unless the transmission system operator and the balancing service recipient agree otherwise, the transmission system operator shall recognise a guarantee of the financial service provider as sufficient security for the fulfilment of liabilities if it has been provided to the balancing service recipient by a financial service provider registered in a Member State of the European Union or European Economic Area, and it conforms to the following conditions:

90.331. the guarantee has been issued by the financial service provider that has or whose group has a long-term credit rating of at least:

90.331.1. Baa1 according to Moody’s or

90.331.2. BBB+ according to Standard & Poor’s, or

90.331.3. BBB+ according to Fitch Ratings.

90.33 2. the guarantee shall be first demand and irrevocable.

[*2 March 2023*]

90.34 The transmission system operator shall determine the amount of the security for the fulfilment of liabilities that shall not be less than EUR 31 000 and shall be twice the amount of the highest net obligations within a month over the last six months or a shorter period if the balancing service has been provided for a shorter period:

90.341. the net liabilities of the balancing service recipient towards the transmission system operator;

90.342. the net liabilities of the transmission system operator towards the balancing service recipient.

[*11 March 2024 / The new wording of Paragraph shall come into force on 1 October 2024. See Paragraph 134.1*]

90.35 The security for the fulfilment of liabilities shall remain valid throughout the duration of the balancing contract or balancing service contract, and also for 45 days after the balancing service recipient has ceased to receive the balancing service from the transmission system operator.

[*2 March 2023*]

90.36 If liabilities of the balancing system recipient within the framework of the balancing contract or balancing service contract exceed the sum for which it has provided the security for the fulfilment of liabilities to the transmission system operator, the transmission system operator has the right to request the balancing service recipient to increase the amount of the security for the fulfilment of liabilities and submit a new security for the fulfilment of liabilities to the transmission system operator within 10 working days that conforms to the requirements of this Code.

[*2 March 2023*]

90.37 The transmission system operator has the right to use the security for the fulfilment of liabilities in order to cover the liabilities of the balancing service recipient towards the transmission system operator if the balancing service recipient fails to pay an invoice for the provided balancing services. After using the security for the fulfilment of liabilities, the transmission system operator shall request the balancing service recipient to restore the security for the fulfilment of liabilities within 10 working days.

[*2 March 2023*]

90.38 If the balancing service recipient fails to provide the required security for the fulfilment of liabilities in accordance with the procedures laid down in the balancing contract or balancing service contract within the amount determined by the transmission system operator or fails to restore the security for the fulfilment of liabilities within 10 days, or if the provided security for the fulfilment of liabilities does not conform to the requirements of this Code, the transmission system operator has the right to terminate the balancing contract or balancing service contract.

[*2 March 2023*]

90.39 Upon termination of the balancing contract or balancing service contract, the transmission system operator shall, within 10 working days after the balancing service recipient has fulfilled all the liabilities towards the transmission system operator, repay the balancing service recipient the amount of the security for the fulfilment of liabilities that was not used to settle outstanding liabilities of the balancing service recipient, or provide the documents releasing the guarantor from its liabilities to secure payments for the balancing service.

[*2 March 2023*]

**4.14. Fee for the Maintenance of Balancing Capacity**

[*16 January 2025*]

90.40 Through the fee for the maintenance of balancing capacity, the balancing service recipient shall cover the costs incurred by the transmission system operator when maintaining balancing capacity procured in accordance with the Baltic balancing capacity market rules approved by the regulator that are developed in accordance with Article 33(1) and Article 38(1) of Regulation 2017/2195.

[*16 January 2025*]

90.41 The transmission system operator shall calculate the fee for the maintenance of balancing capacity for the balancing service recipient for the settlement period as follows:

MR,n = EfT,n\* CRT1 + EimT,n\* CRT2, where:

MR,n – fee for the maintenance of balancing capacity for the balancing service recipient for the settlement period T (EUR);

n – a specific balancing service recipient;

T – settlement period;

EfT,n – the quantity of electricity consumed within the imbalance area of the balancing service recipient n during the settlement period T (MWh);

EimT,n – the absolute total imbalance of the balancing service recipient n for the settlement period T (MWh) calculated as the sum of imbalance in both directions by applying a positive value;

CRT1 – the price of the maintenance of balancing capacity applicable to the quantity of electricity consumed within the imbalance area of the balancing service recipient for the settlement period T (EUR/MWh);

CRT2 – the price of the maintenance of balancing capacity applicable to the absolute total imbalance of the balancing service recipient for the settlement period T (EUR/MWh).

[*16 January 2025*]

90.42 The prices of the maintenance of balancing capacity for the settlement period T shall be calculated as follows:

|  |  |  |
| --- | --- | --- |
| CRT1 = | MRT |   |
| 2 \* EpT |

|  |  |  |
| --- | --- | --- |
| CRT2 = | MRT | , where: |
| 2 \* EimpT |

MRT – a forecast of the maintenance costs of balancing capacity for the settlement period T (EUR) which includes correction for the amount of maintenance costs of the accumulated or unrecovered balancing capacity from the settlement periods before the publication of price in accordance with Paragraph 90.43 of this Code;

EpT – a forecast of electricity consumption of all balancing service recipients during the settlement period T (MWh);

EimpT – a forecast of absolute total imbalance of all balancing service recipients during the settlement period T (MWh).

[*16 January 2025*]

90.43 The transmission system operator shall publish on its website the calculated prices of the maintenance of balancing capacity for the settlement period not later than two months before the applicable settlement period.

[*16 January 2025*]

**4.15. Administration Costs**

[*16 January 2025*]

90.44 The transmission system operator shall administer the balancing regulation service market, and also the imbalance settlements. For the administration of these processes, the balancing service recipient shall pay an administration fee to the transmission system operator which shall be determined by the transmission system operator based on the actual costs of the transmission system operator for the administration of these processes.

[*16 January 2025*]

90.45 The transmission system operator shall publish on its website the administration fee agreed upon with the regulator and the methodology for determination thereof and calculation of payments of the balancing service recipient.

[*16 January 2025*]

**5. Electricity Accounting**

**5.1. Fundamental Principles of Electricity Accounting**

91. System participants shall ensure electricity accounting in accordance with the following fundamental principles:

91.1. when establishing a new system connection, the system participant shall install an appropriate commercial electricity accounting meter (hereinafter – the accounting meter) in accordance with the requirements laid down in Annex 2 to this Code, the connection contract, and the system service contract, and the system operator shall organise the integration of the commercial accounting meter into the automated electricity accounting system (hereinafter – the AEAS) if the forecasted amount of electricity flowing through exceeds 2500 kWh/per year:

91.2. the system participant and the system operator shall specify the proprietary border of electrical equipment in the system service contract;

91.3. the system operator shall provide all system participants within the territorial area of its licence with the accounting meters that conform to the requirements laid down in Annex 2 to this Code;

91.4. the system operator shall ensure the metrological and other periodic inspections of the accounting meter (meters and instrument transformers) as specified by the manufacturers of the accounting meter elements;

91.5. the system operator may use the services of an independent metering service provider for the purchase, installation, and maintenance of the accounting meter;

91.6. the system operator shall use AEAS for obtaining accounting data;

91.7. the system operator shall ensure that the participant has access to its accounting data in the accounting database of the system operator;

91.8. the system operator shall establish and maintain an accounting register that conforms to the requirements laid down in Annex 3 to this Code.

92. The system operator shall determine the fee for access to accounting meters, AEAS, or accounting register data and publish it on its website.

[*30 May 2019*]

**5.2. Inspections of Accounting Meters**

93. Costs of the inspection of an accounting meter shall be covered by the system participant who has requested the inspection thereof. If the accounting meter does not conform to the requirements laid down in Annex 2 to this Code, all costs related to the inspection shall be covered by the system operator.

94. The system operator shall periodically, but not less frequently than specified by the manufacturer of the accounting meter, verify the recorded inspection results of each accounting meter in the accounting register and organise the inspection of the accounting meter to ascertain that the accuracy of the accounting meter conforms to the requirements laid down in Annex 2 to this Code.

95. If it is established during the accuracy inspection of the accounting meter that its accuracy does not conform to the requirements laid down in Annex 2 to this Code, the system operator shall make corrections in the measurement data based on the data change statement which is agreed upon with the system participant.

96. The system participant and the market participant have the right to request that the system operator ensures the inspection of the accounting meter.

97. The system operator shall notify all the system participants and market participants who use an accounting meter regarding the results of the inspection of the respective accounting meter.

98. The market participant and the system operator shall be obliged to immediately inform each other of any established malfunctions of the accounting meter, indicating the duration of the malfunction.

99. If the accuracy of the accounting meter does not conform to the requirements laid down in Annex 2 to this Code, the system operator shall perform the necessary activities as soon as possible to restore the conformity of the accounting meter to the requirements laid down in Annex 2 to this Code.

**5.3. Electricity Accounting Meters**

100. An electricity accounting meter may include the following elements:

100.1. an electricity meter;

100.2. instrument transformers (current and voltage transformers);

100.3. a protected control cable from instrument transformers to meters;

100.4. accounting distribution or a suitably designed panel on which the meter is installed;

100.5. backup power supply (for the meter);

100.6. testing connections (terminal box or test blocks);

100.7. fuses or protective circuit breakers in the accounting voltage circuits if alarm signalling is installed.

101. The accuracy class of the accounting meter and the accuracy requirements for the accounting elements to be installed at each measuring point shall be determined in accordance with Annex 2 to this Code.

102. The control accounting meter may have the same accuracy class as the accounting meter or one accuracy class lower.

103. If more than one market participant uses the accounting meter at the relevant connection point, each market participant shall enter into an agreement with the system operator for the use of the specific accounting meter.

**5.4. Electricity Accounting Data**

104. The method and procedures for obtaining the accounting data of the accounting meter shall be laid down in the electricity system use or system service contract.

105. The data of the accounting meter shall be used as the primary data source for mutual settlements with the market participant and system participant.

106. The data of the control meter shall be used to verify, confirm, or replace the data of the accounting meter in accordance with the principles laid down in Paragraph 91 of this Code.

107. The system operator shall read the accounting data by using AEUS. If the meter of the system participant is connected to instrument transformers, then the hourly data of the meter in AEUS shall be used as the basis for determining the load profile. If a direct connection meter is installed for the electrical installation of the system participant, then the standard load curves in AEUS shall be used as the basis for determining the load profile, unless otherwise agreed between the system operator and the system participant.

108. The system operator has the right to read the accounting data without using remote reading possibility directly from the accounting meter, using electronic devices designed for this purpose if:

108.1. it is impossible to read the data of the accounting meter using AEUS for technical reasons;

108.2. it is necessary to perform data verification and comparison.

109. The system operator shall be responsible for automated obtaining of accounting data from the accounting meter and the storage of such data in the AEUS accounting database.

110. The system operator shall use AEUS for the automated reading, storage in the database, data processing, and viewing of accounting data, and also for auditing, validation, and substitution thereof.

111. The system operator shall ensure installation of the AEUS connection for the accounting meter.

112. The system operator may, upon request of the market participant, allow the market participant to use its own AEUS if it is technically feasible. In this case, the market participant shall cover the costs associated with the replacement of the accounting meter, AEUS changes, or access of the market participant to the AEUS data.

113. The system operator shall establish, maintain, and administer the accounting database which stores data about each accounting meter registered by the system operator.

114. The accounting database shall record the initially read data, substitutions, and calculated values thereof.

115. The system operator shall ensure retention and archiving of the data in the accounting database, and access to these data for data users.

116. The substitution of data in the accounting database with other data shall only be acceptable if incomplete or incorrect data have been stored in the accounting database due to an AEUS error. In this case, the system operator does not have the right to delete the incorrect data from the accounting database. Corrected data entries shall be marked in the accounting database as corrected.

117. For the purpose of data storage, the technical parameters of the accounting database shall be selected in order to ensure the following:

117.1. storage of electricity settlement data – 18 months in non-archived form and 10 years in archives;

117.2. storage of load profile data – 5 months in non-archived form and 2 years in archives;

117.3. storage of other accounting meter data – 1 year in non-archived form and 2 years in archives.

118. The market participant has the right to request the system operator to verify the conformity of the accounting database data with the accounting meter data of the market participant.

119. If the accounting meter data differ from the accounting database data, priority shall be given to the accounting meter data. The system operator shall make the necessary corrections in the accounting database.

120. The system operator shall be responsible for the verification, validation, and substitution of the accounting data.

121. The system operator and the system participant shall lay down the procedures for data verification and validation in the system service contract.

122. The system operator shall use verification measurement data of the accounting meter for the verification and validation of accounting data.

123. If the verification measurement data is unavailable, the system operator shall prepare a substitute measurement data value by using a method agreed upon with the market participant.

124. If the system operator establishes the loss of measurement data or incorrect measurement data received from the accounting meter, it shall alert the market participant thereof within 24 hours from establishing the fact.

125. Prior to commencement of the commercial accounting service, the system operator and the market participant shall enter into a system service contract determining the system services, the available technical support, the measurement performance criteria, and also the conditions under which the system operator ensures that the relevant market participant is informed of the accounting data.

**5.5. Requirements for the Security of Electricity Accounting Meters and Data**

126. The system operator shall ensure that the accounting meter and its associated connections and wiring are protected against unlawful interference.

127. The system operator shall provide the market participant with a user name and password to access the accounting database according to the powers of each market participant.

128. The market participant shall be responsible for the use and confidentiality of the user name and password assigned thereto.

129. The system operator shall ensure the protection of the accounting meter and the accounting data stored in the accounting database.

130. The following persons have the right to access the accounting meter data, the accounting database, or the accounting register:

130.1. the system operator that owns the respective accounting meters;

130.2. the electricity system participant and the market participant that are related to the specific electricity accounting point;

130.3. the metering service provider that is related to the specific accounting point.

131. The system operator shall provide the authorised persons with access to the accounting meter data and the database.

132. The system operator shall electronically register each access to the database, ensuring identification of the data capturer.

133. Only the system operator has the right to change the accounting meter parameters or installed values, after having agreed upon the changes with the relevant electricity system participant.

134. The system operator shall register all changes made in the accounting register.

134.1 [3 October 2024]

**6. Closing Provisions**

135. Decision No. 1/3 of the Public Utilities Commission of 24 February 2010, Network Code (*Latvijas Vēstnesis*, 2010, No. 34(4226), is repealed.

135.1 The balancing market time unit laid down in Sub-paragraph 2.39.1 of this Code shall be a one-hour period that starts on the full hour until the moment the balancing market is organised in accordance with Article 20(6) or Article 21(6) of Regulation 2017/2195.

[*3 October 2024*]

135.2 The transmission system operator shall apply Sub-chapter 4.14 of this Code starting from 1 July 2025.

[*16 January 2025*]

135.3 When calculating the fee for the maintenance of balancing capacity for settlement periods from 1 July 2025 to 31 December 2025, the transmission system operator shall apply a uniform price for the maintenance of balancing capacity that is attributable to the quantity of electricity consumed by the balancing service recipient within the imbalance area and a price for the maintenance of balancing capacity that is attributable to the absolute total imbalance of the balancing service recipient which the transmission system operator shall publish on its website not later than by 1 February 2025 following agreeing upon thereof with the regulator.

[*16 January 2025*]

135.4 When calculating the prices for the maintenance of balancing capacity referred to in Paragraph 90.42 of this Code for the settlement periods from 1 January 2026 to 31 December 2026, the transmission system operator shall apply a correction for the amount of maintenance costs of the accumulated or unrecovered balancing capacity for the settlement periods from 1 July 2025 to 31 December 2025.

[*16 January 2025*]

135.5 The transmission system operator shall include the actual administration costs of the balancing regulation service market in the administration fee referred to in Paragraph 90.44 of this Code, starting from 1 July 2025.

[*16 January 2025*]

135.6 The transmission system operator shall publish the information referred to in Paragraph 90.45 of this Code by 8 February 2025.

[*16 January 2025*]

135.7 The transmission system operator shall, by 14 January 2028, submit to the regulator the evaluation regarding the results of the application of the model for the attribution of the maintenance costs of balancing capacity, conformity of the model with the actual situation on the electricity market, and an assessment of the necessary changes in the Network Code.

[*16 January 2025*]

136. The Network Code shall come into force on the day following its publication in the official gazette *Latvijas Vēstnesis*.

Acting in the capacity of the Chair of the Board of the Public Utilities Commission, the Supervisory Board Member R. Irklis

**Annex 1**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*16 January 2025 / The new wording of Paragraph 1 of Annex shall come into force on 8 February 2025. See Paragraph 2 of the Decision*]

**Frequency and Voltage Levels for Ensuring the Stable Operating Mode**

1. The operational parameters and requirements of the Continental European Synchronous Area shall be applicable to the Latvian electricity system.

2. The nominal voltage (UN) of the network shall be the voltage used to designate or identify the relevant electricity grid of the system operator for which specific characteristics have been laid down. The nominal voltage levels shall be as follows: 330 kV; 110 kV; 20 kV; 10 kV; 6 kV; 1 kV; 0.4 kV and 0.23 kV.

3. Electricity quality requirements shall be defined in the existing laws and regulations, including standards.

4. The standard requirements shall also be applicable to 330 kV voltage equipment.

Acting in the capacity of the Chair of the Board of the Public Utilities Commission, the Supervisory Board Member R. Irklis

**Annex 2**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*2 March 2023*]

**Types and Accuracy of Accounting Meters**

1. Electricity accounting meters shall conform to the following accuracy class:

|  |  |
| --- | --- |
| Accounting group | Accuracy class not lower than |
| Meter | Instrument transformers |
| active power | reactive power |
| At cross-border interconnections with a voltage of 110 kV and higher\* | 0.2 s | 1.0 | 0.2 s\*\*\* |
| For the electricity producers with a connection to a 110 kV and higher voltage electrical grid | 0.2 s | 1.0 | 0.2 s\*\*\* |
| For customers in the system with a connection to a 110 kV and higher voltage electrical grid | 0.5 or C | 2.0 | 0.5 s\*\*\*\* |
| For customers in the system with a connection to a medium-voltage and low-voltage grid, and control accounting (accounting with instrument transformers) | 0.5 or C | 2.0 | 0.5 |
| For customers in the system with a connection to a low-voltage grid with direct connection meters | 1.0 or B | 2.0\*\* |  |

\* the accuracy class of accounting for cross-border interconnections shall be mutually agreed upon by the respective transmission system operators

\*\* only for three-phase electricity meters

\*\*\* the class s shall only be applicable to instrument transformers or current windings of combined instrument transformers, voltage transformers shall conform to the class 0.2

\*\*\*\* the class s shall only be applicable to instrument transformers or current windings of combined instrument transformers, voltage transformers shall conform to the class 0.5

2. Depending on the amount of electricity flowing through the accounting point, the following requirements shall be laid down for the control meter, unless otherwise specified by the system operator:

|  |  |  |
| --- | --- | --- |
| Type | Electricity (GWh/per year) at the accounting site | Requirements for the control meter |
| 1 | more than 1000 | as laid down in Paragraph 6 of this Annex |
| 2 | between 100 and 1000 | as laid down in Paragraph 8 of this Annex |
| 3 | less than 100 | No special requirements |

3. The system participant may install an accounting meter with a higher accuracy class than that laid down in Paragraph 1 of this Annex.

4. Accounting meters that do not conform to the requirements of the Network Code may only be used for a specific time period, upon mutual agreement between the system participants.

5. It is prohibited to use a winding of an instrument transformer (current transformer or voltage transformer) with an accuracy class lower than 0.5 for commercial accounting of electricity.

6. A control meter shall include a separate accounting meter that uses a separate secondary circuit of the voltage transformer and a separate core of the current transformer.

7. If the accuracy class of the verification accounting meter is the same as that of the accounting meter, the average reading of both accounting meters may be used to determine the amount of energy to be measured.

8. If the quantity of electricity at the electricity accounting site is between 100 and 1000 GWh per year, then the control meter shall refer to the use of curve profile data (with an integration period of 60 or 30 min) or operational data available in electronic format in the verification/validation process.

9. When designing an accounting meter, the following requirements shall be taken into account:

9.1. for accounting equipment with an amount of electricity flowing through of more than 1000 GWh per year per accounting point, a separate current transformer core shall be provided for the accounting which may not be used for any other purpose, unless otherwise agreed with the system operator;

9.2. secondary windings of instrument transformers shall be be connected to the accounting, so that the voltage losses in the secondary circuits do not exceed the acceptable amount, and also the number of connections shall be minimised. Connections between the instrument transformers and the meter shall be be made by using a shielded control cable;

9.3. the system operator shall ensure the storage of the accounting diagrams and documentation necessary for the maintenance and verification of accounting meters.

Acting in the capacity of the Chair of the Board of the Public Utilities Commission, the Supervisory Board Member R. Irklis

**Annex 3**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

**Accounting Register**

1. The accounting register shall constitute a database established and maintained by the system operator that contains statistical information about the accounting meters laid down in this Code.

2. The purpose of the accounting register shall be to:

2.1. register connection sites, accounting points;

2.2. verify and confirm conformity of the data;

2.3. record changes in the registered information, maintaining a history of changes.

3. The data in the accounting register shall be confidential.

4. The accounting register shall include the following information:

4.1. detailed information about the connection and accounting point, including:

4.1.1. location information (for example, drawing numbers);

4.1.2. detailed information about the calculations of compensation for losses;

4.1.3. identification name of location;

4.1.4. detailed information about the market participants related to the connection point;

4.1.5. information about the person responsible for the accounting meter.

4.2. identity and characteristics of the accounting meter components (meters and instrument transformers):

4.2.1. factory numbers;

4.2.2. identification name;

4.2.3. type;

4.2.4. transformation coefficients of the instrument transformers;

4.2.5. calibration tables, where they are required to achieve the accuracy of the accounting meter;

4.2.6. total values and coefficients.

4.3. information about the data communication, including:

4.3.1. telephone number for access to the data;

4.3.2. type and serial number of communication equipment;

4.3.3. information about the communication protocol or references;

4.3.4. information about the data conversion;

4.3.5. user identification and access rights;

4.3.6. passwords for reading data from the accounting equipment and for making corrections (to be located in a hidden or protected field).

4.4. data verification/validation process agreed upon by the involved parties, including:

4.4.1. algorithms;

4.4.2. data comparison methods;

4.4.3. processing and warnings (for example, voltage source limits, deviation angle limits);

4.4.4. alternative data sources.

Acting in the capacity of the Chair of the Board of the Public Utilities Commission, the Supervisory Board Member R. Irklis

**Annex 4**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*5 December 2019; 17 September 2020; 2 March 2023*]

**Inspections of Electrical Equipment**

1. For new and modified electrical equipment to be connected to the electricity system, at least the following inspections shall be carried out, unless otherwise specified by the relevant system operator in the procedures for the operational notification of the power plant:

1.1. for the power-generating module, the following shall be performed:

1.1.1. electricity quality measurements at the connection point (this shall not apply to the type A power park module);

1.1.2. inspection for the remote disconnection from the electricity system in accordance with the requirements laid down in Article 13(6) of Regulation 2016/631 (this shall apply to the type A power-generating module with the remote disconnection requirement);

1.1.3. active power controllability test:

1.1.3.1. for the type B power-generating module in conformity with Sub-paragraph 11.3 of Annex 7 to this Code;

1.1.3.2. for the type C or D power-generating module in conformity with Sub-paragraphs 19.3 and 19.4 of Annex 7 to this Code;

1.2. for the demand facility which is to be connected to the transmission system, a conformity simulation for functioning of the demand facility in steady-state and dynamic modes shall be carried out in conformity with the requirements laid down in Regulation 2016/1388, if it is requested by the transmission system operator.

2. For a power-generating module considered as an existing power-generating module within the meaning of Regulation 2016/631, one or more of the following inspections shall be conduced upon request of the relevant system operator:

2.1. electricity quality measurements at the connection point;

2.2. inspection of the manual start-up and synchronisation of the power-generating module;

2.3. inspection of the disconnection of the power-generating module from the electricity transmission system with automatic synchronisation with the electricity transmission system;

2.4. inspection of the turbine rotation speed limiter;

2.5. inspection of the turbine speed governor response;

2.6. checking on the conformity of the automatic excitation regulator;

2.7. inspection of the automatic excitation regulator with the system stabiliser turned on and off;

2.8. inspection of the load and shedding speed of the power-generating module;

2.9. inspection of the load-shedding arrangement in the event of failure of the power-generating module;

2.10. inspection of the minimum excitation current limiter;

2.11. inspection of frequency regulation in the electricity grid;

2.12. assessment of ensuring reactive power capability in the context of the varying voltage profile at the connection point (U-Q/Pmax profile);

2.13. inspection of the transition to self-consumption mode;

2.14. inspection of operation of the power-generating module in the event of voltage changes in the electricity system;

2.15. inspection of operation of the power-generating module in the event of disturbances in the electricity system, including the inspection of active power limitation of the power-generating module by selecting such disturbance cases in the electricity system that are protective for the equipment;

2.16. inspection of ensuring constant reactive power value of the power-generating module.

**Annex 5**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*2 March 2023*]

**Applicable Tests and Inspections During the Inspection of Synergy of Electrical Equipment of Final Customers with the Electricity Transmission System**

1. Electricity quality measurements at the connection point.

2. Inspection of the recovery procedure of the final customer’s equipment in the event of disturbances in the electricity system.

3. Synchronisation of the final customer’s equipment in the events of different voltage and frequency values, phase angle deviations, and voltage and frequency fluctuations in the electricity system (for the final customer’s equipment capable of operating in the island operation mode).

4. Disconnection of the final customer’s equipment from remote control.

5. Disconnection of the load determined for the final customer’s equipment in the event of decreased frequency.

6. Disconnection of load of the final customer’s equipment in the event of decreased voltage in the electricity system.

7. Data exchange between the final customer’s equipment and the transmission system operator.

Acting in the capacity of the Chair of the Board of the Public Utilities Commission, the Supervisory Board Member R. Irklis

**Annex 6**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

**General Scheme for the Calculation of the Total Transmission Capacity and the Transmission Reliability Margin**

[2 March 2023]

**Annex 7**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*2 March 2023*]

**Network Connection Requirements for the Power-generating Modules**

1. The network connection requirements for the power-generating modules shall be laid down based on Article 7(1) of Regulation 2016/631 and shall be applicable in accordance with the requirements laid down in Regulation 2016/631.

2. A power-generating module (hereinafter – the module) shall be considered a specific type of module starting from the following power threshold:

2.1. type A module – 0.0008 MW;

2.2. type B module – 0.5 MW;

2.3. type C module – 5 MW;

2.4. type D module – 15 MW.

3. Type A module shall conform to the following requirements in respect of the frequency stability:

3.1. as regards the frequency ranges, the module shall be capable of remaining connected to the network and operating within the following frequency ranges and periods:

3.1.1. 47.5–48.5 Hz for at least 30 minutes;

3.1.2. 48.5–49.0 Hz for at least 30 minutes;

3.1.3. 49.0–51.0 Hz indefinitely;

3.1.4. 51.0–51.5 Hz for at least 30 minutes;

3.1. as regards the withstand capability of rate of change of frequency, the module shall be capable of remaining connected to the network and operating at a frequency change rate from 0 to ±2.5 Hz/s if it conforms to the operational condition of the module.

4. Type A module in the limited frequency sensitive mode – increased frequency (LFSM–O) – shall be capable of activating active power frequency response capability (Figure 1) with the following settings:

4.1. the frequency threshold shall be 50.2 Hz;

4.2. the droop setting shall be 5 %, the droop shall be adjustable within the range of 2 % to 12 %;

4.3. in the event of frequency increase, the initial power change response shall be as follows:

4.3.1. for the synchronous module – ≤ 2 seconds;

4.3.2. for the park module without inertia – ≤ 0.2 seconds;

4.3.3. for the park module with inertia – ≤ 2 seconds;

4.4. in the event of frequency increase, the module shall be capable of activating the full active power frequency response within the range from the maximum power to the minimum power regulation level at the maximum rate that ensures stable operation of the module, but for not longer than:

4.4.1. the synchronous module – according to the technical capabilities of the equipment;

4.4.2. the park module without inertia – within 2 seconds;

4.4.3. the park module with inertia – within 30 seconds.



Fig. 1. Active power frequency response capability of the type A modules in the limited frequency sensitive mode – increased frequency (LFSM–O),

where:

Pref – reference active power which is related to the change in the active output power of the module (MW);

ΔΡ – change in the active output power of the module;

fn – nominal network frequency (Hz);

Δf – change in the network frequency;

S2 – droop setting (%).

5. The transmission system operator shall, based on the technical justification of the module’s owner, determine the activation time for the full active power frequency response and the initial power change response according to the structural characteristics of the module if the module is not capable of ensuring the settings laid down in Sub-paragraphs 4.3.2–4.4.3 of this Annex due to its structural characteristics.

6. At an outside temperature of 15 °C, atmospheric pressure of 1.013 bars, and relative humidity of 60 %, it shall be permissible for the type A module to have reduced maximum active power at the frequency drop below 49 Hz if the reduction rate for a frequency drop of 1 Hz is 2 % of the maximum power at the frequency of 50 Hz (Figure 2). The module’s owner shall submit to the relevant system operator the data about the active power reduction at the frequency drop below 49 Hz at least across a temperature range of -10 °C to +30 °C.



Fig. 2. The permissible maximum power capability reduction for the type A module at a decreasing frequency,

where:

Pmax – maximum power of the module (MW);

f – network frequency (Hz).

7. The type A module shall be allowed to automatically connect to the network if:

7.1. the network frequency has reached a value within the range of 49.8 Hz to 50.05 Hz and stays within this range for at least 60 seconds;

7.2. after an unplanned disconnection from the network caused by disturbances in the network, the module restores the active power set previously at a rate not exceeding 20 % of Pmax/minute.

8. The type B module shall conform to the requirements laid down in Paragraphs 3–7 of this Annex for the type A module.

9. As regards the capability of fault-ride -through in the event of symmetrical and asymmetrical faults, the type B module shall be capable of remaining connected to the network and continue stable operation after the operation of the electricity system is disrupted by identified faults in the transmission system, having regard to the fault-ride-through profile laid down in Figures 3 and 4 under both pre-fault and post-fault conditions at the connection point.



Fig. 3. Fault-ride-through profile of the type B synchronous module,

where:

U (p.u.) – voltage reference value;

Uret – voltage maintained at the connection point during the fault;

Uclear – voltage at the moment when the fault is cleared;

Ureci – the lower limits of voltage recovery during time i after the fault clearance;

t – time (s);

tclear – the moment when the fault is cleared (s);

treci – the time i when the lower limits of voltage recovery are reached after the fault clearance (s).



Fig. 4. Fault-ride-through profile of the type B park module.

10. After an unplanned disconnection from the network caused by disturbances in the network, the type B module shall be capable of restoring connection to the network after the system is restored in the stable operating mode, where voltage is within the range of 0.9–1.1 of the reference voltage value and frequency is within the range of 49.0–50.2 Hz.

11. The type B module shall be capable of ensuring the real-time exchange of the following information with the relevant system operator, unless the relevant system operator has determined otherwise in the technical requirements:

11.1. active power at the connection point or an equivalent measurement of active power;

11.2. command regarding limitation of active power;

11.3. after receipt of the command regarding limitation of active power, the module shall reduce the output power at a rate which corresponds to the structural characteristics of the module and shall take into account the limitation with a tolerance of not more than 5 % of Pmax.

12. In addition to the requirements for resilience laid down in Paragraphs 8–11 of this Annex, the type B synchronous module shall be capable of ensuring that post-fault active power is restored in the amount of at least 70 % of the pre-fault active power value within not more than 10 seconds.

13. In addition to the requirements for resilience laid down in Paragraphs 8–11 of this Annex, the type B park module shall be capable of ensuring the following:

13.1. the start of restoration of post-fault active power when the voltage at the connection point is not lower than 90 % of the nominal voltage value;

13.2. restoration of post-fault active power in the amount of at least 70 % of the pre-fault active power value with an accuracy of ±5 %, within not more than 10 seconds.

14. The type C module shall conform to the requirements laid down in Paragraphs 3–7 of this Annex for the type A module and in Paragraphs 9–10 of this Annex for the type B model.

15. The C type module shall ensure the real-time exchange of the following information with the relevant system operator and the transmission system operator (if it is not the relevant system operator), unless the relevant system operator has determined otherwise in the technical requirements:

15.1. active power at the connection point or an equivalent measurement of active power;

15.2. available power at the connection point (for wind, solar power-generating modules) (MW);

15.3. active power setting;

15.4. command regarding change of the active power setting;

15.5. FSM mode state “On/Off”;

15.6. FSM mode droop setting;

15.7. FSM mode deadband setting;

15.8. signals necessary for the operation of frequency restoration controller according to the list published on the website of the transmission system operator;

15.9. reactive power at the connection point (MVAr);

15.10. voltage at the connection point (kV);

15.11. current at the connection point (A);

15.12. command regarding change of the voltage setting;

15.13. command regarding change of the reactive power setting;

15.14. command regarding switching between voltage and reactive power regulation modes.

16. Type C module shall correspond to the following requirements in respect of the frequency stability:

16.1. the active power setting assigned by the transmission system operator shall be reached at a rate that is technically feasible but not smaller than the minimum values laid down in Sub-paragraph 19.3 of this Annex with an accuracy of ±5% or higher;

16.2. if the automatic remote control devices are not working, manual local measures shall be acceptable. In this case, the time for change in the active power setting shall be as short as possible, according to the technical capabilities of the power-generating module;

16.3. in the limited frequency sensitive mode – decreased frequency (LFSM-U) – the module shall be capable of activating active power frequency response capability (Figure 5) with the following settings:

16.3.1. the frequency threshold shall be 49.8 Hz;

16.3.2. the droop setting shall be 5 %, unless the relevant system operator has specified otherwise;



Fig. 5. Active power frequency response capability of the type C module in the limited frequency sensitive mode – decreased frequency (LFSM-U).

16.4. in the event of frequency reduction, the module shall be capable of activating the full active power frequency response within the range from the minimum regulation level to the maximum power at the maximum rate that ensures stable operation of the module, but for no longer than:

16.4.1. the synchronous module – according to the technical capabilities of the module;

16.4.2. the park module without inertia – 2 seconds;

16.4.3. the park module with inertia – 30 seconds;

16.5. in the event of frequency reduction, the initial power change response time shall be less than:

16.5.1. for the synchronous module – 2 seconds;

16.5.2. for the park module without inertia – 0.2 seconds;

16.5.3. for the park module with inertia – 2 seconds;

16.6. the transmission system operator shall, based on the technical justification of the module’s owner, determine a longer activation time for the full active power frequency response and the initial power change response if the module is not capable of ensuring the settings laid down in Sub-paragraphs 16.4.2–16.5.3 of this Annex due to its structural characteristics;

16.7. it shall be capable of ensuring the active power frequency response in the frequency sensitive mode (FSM), taking into account Sub-paragraphs 16.2–16.4 of this Annex and all of the following parameters:

16.7.1. active power change range at the maximum power,  – 10 %;

16.7.2. frequency response deadband Δfi – not greater than 10 mHz;

16.7.3. frequency response deadband shall not exceed 10 mHz and adjustable within the range from 0 mHz to 200 mHz;

16.7.4. droop s1 shall be adjustable within the range from 2 % to 12 %, default value of 5 %;

16.7.5. after receipt of the transmission system operator’s command, it shall be capable of activating the frequency sensitive mode (FSM) within not more than 5 minutes;

16.8. in the event of abrupt changes in frequency, it shall be capable of fully activating the active power frequency response within 30 seconds, with an initial delay not exceeding two seconds (Figure 6);



Fig. 6. Active power frequency response capability of the type C module,

where:

ΔΡ1/Pmax – the active power range in relation to the maximum power (%);

t1 – the maximum allowable initial delay (s);

t2 – the time for full activation (s);

16.9. it shall be capable of ensuring full active power frequency for 30 minutes.

17. As regards the voltage stability, the type C module shall be capable of automatic disconnection if the voltage at the connection point reaches:

17.1. 80 % of the nominal value (minimum value) and remains below this value for at least 3 seconds;

17.2. 120 % of the nominal value (maximum value) and remains above this value for at least 1.5 seconds.

18. The type C module with black start capability shall meet the following requirements in respect of the system recovery:

18.1. after the shutdown, it is capable of restoring operation from the off state without external power supply within one hour;

18.2. it is capable of continuing operation after switching to houseload operation, regardless of any additional connections to the external network with a minimum operating time of six hours.

19. The type C module shall meet the following general system management requirements:

19.1. in order to identify weakly damped power fluctuations, the module shall be equipped with a dynamic behaviour recording device of the system (hereinafter – the recorder), which is capable of recording voltages, currents, active and reactive power, frequency, rate of change of frequency, and also recording direct and opposite sequence components of voltage, current, active and reactive power. The recorder shall be capable of recording voltages, currents, active and reactive power in algebraic (a+jb) and polar (amplitude, angle) formats. The recorder shall be capable of starting operation from the external signals by using binary inputs of the device and from the built-in measurement, protection functions. It shall be ensured that the data obtained by the recorder are stored, archived, and also displayed in real time. The electricity producer shall determine a data transmission protocol of the recorder by agreeing upon with the transmission system operator;

19.2. the maximum rate of changes in the active output power shall be 200 MW/min;

19.3. the minimum rate of change in the active output power shall be as follows:

|  |  |  |
| --- | --- | --- |
| Type of module | Change in the active output power at the nominal power in one minute (%) | Power range at the maximum power (%) |
| Gas or liquid fuel module | 8 | 60–90 |
| Combined (gas and steam) module | 8 | 60–90 |
| Coal and solid fuel module | 4 | 60–90 |
| Solar or wind module | 50 | 20–100 |
| Hydroelectric power station module | 50 | 0–100 |

19.4. the tolerance for active power regulation shall not exceed 2 % of Pmax. Lower output power shall be permissible if determined by the availability of the primary energy source.

20. In addition to the provisions laid down in Paragraph 12 and Paragraphs 14–19 of this Annex regarding the voltage stability, the type C synchronous module shall ensure reactive power capability at maximum active power which corresponds to the technical capabilities of the module but is not less than the reactive power capability indicated in Figure 7 in relation to the variable voltage profile at the connection point (U-Q/Pmax profile).



Fig. 7. U-Q/Pmax profile of the type C synchronous module,

where:

Q – reactive power;

Pmax – maximum active power;

U – voltage at the connection point;

 – U-Q/Pmax profile boundaries.

21. In addition to the provisions of Paragraphs 13–19 of this Annex, the type C park module shall meet the following requirements:

21.1. regarding the frequency stability, the operating principles of the control systems installed for ensuring synthetic inertia and the related performance parameters shall be agreed upon with the transmission system operator;

21.2. regarding the voltage stability:

21.2.1. the U-Q/Pmax profile laid down in Figure 8 shall be ensured:



Fig. 8. U-Q/Pmax profile of the type C park module.

21.2.2. it shall be ensured that the reactive power capability of the module in relation to varying active power corresponds to the technical capabilities of the module but is not less than the profile laid down in Figure 9 (U-Q/Pmax profile):



Fig. 9. P-Q/Pmax profile of the type C park module,

where:

P (p.u.) – power reference value;

 – P-Q/Pmax profile boundaries;.

21.2.3. it shall be capable of controlling the power factor at the connection point. The relevant system operator shall determine the target value of the power factor, taking into account that after abrupt changes in active power, the module shall be capable of ensuring changes in the reactive power output in the amount of 90 % within three seconds and stabilise within 60 seconds at a value dependent on the target value of the power factor. The power factor tolerance in the steady-state mode shall not exceed the value that corresponds to 5 % of the maximum reactive power;

21.2.4. in the faults requiring fault-ride-through capability, the priority shall be given to reactive power contribution.

22. The type D module shall conform to the requirements laid down in Paragraphs 3–7 of this Annex for the type A module, Paragraphs 9–10 for the type B module, and Paragraph 15, 16, 18, and 19 for the type C module.

23. If the voltage has deviated from the reference voltage value, the type D module shall be capable of operating without disconnecting from the network within the following period and voltage range at the connection point of the electricity transmission system:

|  |  |  |
| --- | --- | --- |
| Voltage value at the connection point of the transmission system | Voltage range | Period of operation |
| 110 kV | 0.85–0.90 p.u.(93.5–99.0 kV) | 30 minutes |
| 110 kV | 0.9–1.118 p.u.(99.0–122.98 kV) | Indefinitely |
| 110 kV | 1.118–1.15 p.u.(122.98–126.5 kV) | 20 minutes |
| 330 kV | 0.88–0.90 p.u.(290.4–297.0 kV) | 20 minutes |
| 330 kV | 0.90–1.097 p.u.(297.0–362.01 kV) | Indefinitely |
| 330 kV | 1.097–1.15 p.u.(362.01–379.5 kV) | 20 minutes |

24. As regards the capability of fault-ride-through capability in the event of symmetric and asymmetric faults, the type D module shall be capable of remaining connected to the network and continue stable operation after the operation of the electricity system is disrupted by identified faults in the transmission system, in accordance with the fault-ride-through (ratio of the reference voltage value and time) profile laid down in Figures 10 and 11 at the connection point.



Fig. 10. Fault-ride-through profile of the type D synchronous module.



Fig. 11. Fault-ride-through profile of the type D park module.

25. In addition to the provisions of Paragraphs 22–24 of this Annex, the type D synchronous module shall meet the requirements laid down in Paragraph 12 of this Annex for the type B synchronous module and in Paragraph 20 for the type C synchronous module.

26. The type D synchronous module shall be equipped with an electricity system stabiliser (ESS) function if requested by the transmission system operator.

27. As regards the voltage stability, the type D synchronous module shall ensure the U-Q/Pmax profile laid down in Figure 12 for 330 kV and 110 kV voltage levels:



Fig. 12. U-Q/Pmax profile of the type D synchronous module for 330 kV and 110 kV voltage levels,

where:

 – U-Q/Pmax profile for 330 kV voltage;

 – U-Q/Pmax profile for 110 kV voltage.

28. In addition to that laid down in Paragraphs 22–24 of this Annex, the type D park module shall meet the requirements laid down in Paragraph 13 of this Annex for the type B park module and in Paragraph 21 for the type C park module.

29. The type D park module the maximum power of which exceeds 15 MW, shall be equipped with an electricity system stabiliser (ESS) function.

30. As regards the voltage stability, the type D park module and offshore park module shall ensure the U-Q/Pmax profile laid down in Figure 13 for 330 kV and 110 kV voltage levels:



Fig. 13. U-Q/Pmax profile of the type D park module and offshore park module for 330 kV and 110 kV voltage levels.

**Annex 8**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*30 May 2019; 2 March 2023; 3 October 2024*]

**Regulations Regarding the Provision of Regulation Service**

1. Regulations for regulation service providers shall be stipulated based on Article 5(4)(c) and Article 18(1)(a) of Regulation 2017/2195.

2. For the purpose of providing the regulation service, a regulation service provider may use the following reserve provision units: regulation product and regulation capacity product reserve supply units and reserve supply groups, taking into account the following conditions:

2.1. a valid system service contract shall be applicable to the reserve provision unit if such a contract must be concluded in accordance with the requirements of laws and regulations;

2.2. the use of the reserve provision unit in the provision of regulation service has been agreed upon with the balancing service provider of this reserve provision unit;

2.3. the reserve provision unit shall meet the technical and data exchange requirements determined and published by the transmission system operator on its website, including requirements for ensuring commercial accounting;

2.4. the regulation service provider has notified the transmission system operator, in accordance with the procedures laid down in the ancillary service contract, regarding the initiation of use of the verified reserve provision unit for the provision of regulation service.

3. In order for the transmission system operator to verify the conformity of the reserve provision unit of the regulation service provider with the requirements laid down in Sub-paragraphs 2.1, 2.2, and 2.3 of this Annex, the regulation service provider shall submit to the transmission system operator an application for the provision of regulation service (hereinafter – the regulation service application). The transmission system operator shall publish on its website the form of the regulation service application and the list of documents to be submitted.

4. The transmission system operator shall examine the regulation service application and the documents attached thereto within 30 days from the day of receipt of the application and inform the regulation service provider of the conformity of the reserve provision unit with the requirements laid down in Sub-paragraphs 2.1 and 2.2 of this Annex.

5. If the reserve provision unit is connected to the distribution system, the transmission system operator is entitled to request the transmission system operator to provide information necessary for the examination of the regulation service application and evaluation of inspections. The distribution system operator shall provide the requested information for the examination of the regulation service application within the time limit set by the transmission system operator, but not later than within 10 working days from the receipt of the request of the transmission system operator. The distribution system operator shall provide the requested information for the evaluation of inspections within the time limit set by the transmission system operator, but not later than within 30 working days from the receipt of the request of the transmission system operator.

6. If, in accordance with Paragraph 4 of this Annex, the transmission system operator has recognised the reserve provision unit of the regulation service provider as conforming to the requirements laid down in Sub-paragraphs 2.1 and 2.2 of this Annex, the transmission system operator and the regulation service provider shall agree on the procedures for verifying the conformity of the reserve provision unit with the requirements laid down in Sub-paragraph 2.3 of this Annex and on the time for this verification.

7. The transmission system operator shall inform the regulation service provider of the results of the verification of the reserve provision unit within 10 working days after conduct of the verification. If the reserve provision unit is connected to the distribution system, the transmission system operator shall inform the regulation service provider of the results of the verification within 10 working days after conduct of the verification and receipt of information from the distribution system operator in accordance with Paragraph 5 of this Annex.

8. If the transmission system operator has recognised the reserve provision unit of the regulation service provider as conforming to the requirements laid down in Sub-paragraphs 2.1, 2.2, and 2.3 of this Annex, the regulation service provider shall notify the transmission system operator, in accordance with the procedures laid down in the ancillary service contract, regarding the initiation of use of the relevant reserve provision unit for the provision of regulation service.

9. The exchange of information related to the provision of regulation service, including operational information, and data between the transmission system operator and the regulation service provider shall be carried out in accordance with the procedures laid down in the ancillary service contract and balancing market rules.

10. If the reserve provision unit to be used for the provision of regulation service is connected to the distribution system, the distribution system operator shall, over the entire period during which the reserve provision unit is used for the provision of regulation services, provide the transmission system operator with information about the following:

10.1. commercial accounting data of the reserve provision unit;

10.2. the balancing service provider of the reserve provision unit engaged in electricity generation that is responsible for the imbalance resulting from electricity generation;

10.3. the balancing service provider of the reserve provision unit consuming electricity that is responsible for the imbalance resulting from electricity consumption.

11. The transmission system operator and the distribution system operator shall mutually agree on the procedures and time limits for the provision of the information laid down in Paragraph 10 of this Annex.

11.1 If the regulation service provider ensures a frequency restoration reserve regulation capacity product, it shall be obliged to provide a regulation energy product which corresponds to the regulation capacity product in terms of amount and type in accordance with the requirements of laws and regulations.

12. The transmission system operator shall include the activated regulation product bids of the regulation service provider as an imbalance correction in the imbalance calculation of the balancing service provider of the reserve provision unit used in the activated regulation product bid, and the amount of this imbalance correction shall be equal to the quantity of energy of the activated regulation product bid.

13. If the balancing service provider of the regulation service provider differs from the balancing service provider of the reserve provision unit used in the activation of the regulation product bid of the regulation service provider, it shall be considered that an energy trading operation has been conducted between the respective balancing service providers the volume of which shall be equal to the quantity of energy of the activated regulation product bid.

14. If balancing has been performed within a coordinated balancing area, the quantity of energy received or delivered within the framework of the regulation service shall be determined by taking into account the following:

14.1. the quantity of energy purchased or sold within the framework of the regulation service by the transmission system operator in a specific balancing market time unit and delivered through normal activation;

14.2. the quantity of energy purchased or sold within the framework of the regulation service by the transmission system operator within the framework of a specific bid and delivered through special activation.

14.1 If balancing has been performed within a control zone, the quantity of energy received or delivered within the framework of the regulation service in a balancing market time unit shall be determined by taking into account the following:

141.1. the quantity of energy purchased or sold within the framework of the regulation service by the transmission system operator in a specific balancing market time unit and delivered through normal activation;

141.2. the quantity of energy purchased or sold within the framework of the regulation service by the transmission system operator within the framework of a specific bid and delivered through local special activation (activation without using the platform referred to in Article 20(6) or Article 21(6) of Regulation 2017/2195);

141.3. the quantity of energy purchased or sold within the framework of the regulation service by the transmission system operator in a specific market time unit and delivered through normal local activation (activation without using the platform referred to in Article 20(6) or Article 21(6) of Regulation 2017/2195) in the cases included in the balancing market rules.

15. If balancing has been performed within a coordinated balancing area, the quantity of energy purchased within the framework of the regulation service by the transmission system operator within a specific trading interval and delivered through normal activation, shall be calculated as follows:

,

where

 – the quantity of regulation energy purchased by the transmission system operator and sold by the regulation service provider within the framework of the regulation service and delivered upward (regulation towards load) through normal bid activation in the trading interval t (MWh);

 – the volume of activated bid power recorded in the order of a normal activation dispatcher’s command (MW);

 – the delivery period of normal activation in hours (from the start time of activation to deactivation time) (h);

a – specific activation;

A – number of activations in the trading interval t.

16. If balancing has been performed within a coordinated balancing area, the quantity of energy sold within the framework of the regulation service by the transmission system operator within a specific trading interval and delivered through normal activation, shall be calculated as follows:

,

where

 – the quantity of energy sold by the transmission system operator and purchased by the regulation service provider within the framework of the regulation service and delivered downward (regulation towards shedding) through normal bid activation in the trading interval t (MWh).

17. If balancing has been performed within a coordinated balancing area, the quantity of energy purchased within the framework of the regulation service by the transmission system operator in a specific bid and delivered through special activation, shall be calculated as follows:

,

where

 – the quantity of regulation energy purchased by the transmission system operator and sold by the regulation service provider within the framework of the regulation service and activated through special activation in the special activation instance n (MWh);

 – the volume of activated bid power recorded in the order of a dispatcher’s command for the activation n of a special regulation product bid (MW);

 – the delivery period of the activation n of a special regulation product bid in hours (from the start time of activation to deactivation time) (h).

18. If balancing has been performed within a coordinated balancing area, the quantity of energy sold within the framework of the regulation service by the transmission system operator in a specific bid and delivered through special activation, shall be calculated as follows:

,

where

 – the quantity of energy sold by the transmission system operator and purchased by the regulation service provider within the framework of the regulation service and activated through special activation in the special activation instance n (MWh).

19. If balancing has been performed within a coordinated balancing area, the regulation service fee in the settlement period for the energy purchased by the transmission system operator and sold to the regulation service provider, and delivered upward (regulation towards load), shall be calculated as follows:

,

where

Mrega – the regulation service fee for the regulation energy purchased by the transmission system operator and sold by the regulation service provider (EUR);

 – the marginal price of normal activation for regulation energy for upward activation in the trading interval t (EUR/MWh);

 – the activated bid price which shall be equal to the price laid down in the bid of the regulation service provider in the special activation instance n (EUR/MWh);

T – number of trading intervals in the relevant settlement period;

t – trading interval;

N – number of special activation instances in the relevant settlement period;

n – special activation of the regulation product bid.

20. If balancing has been performed within a coordinated balancing area, the regulation service fee in the settlement period for the quantity of energy sold by the transmission system operator and purchased by the regulation service provider, and delivered downward (regulation towards shedding), shall be calculated as follows:

,

where

Mregl – the regulation service fee for the regulation energy sold by the transmission system operator and purchased by the regulation service provider (EUR);

 – the marginal price of normal activation for downward activation in the trading interval t (EUR/MWh);

 – the activated bid price which shall be equal to the price specified in the bid of the regulation service provider in the special activation instance n (EUR/MWh).

20.1If balancing has been performed within a control zone, the quantity of energy purchased or sold within the framework of the regulation service by the transmission system operator in a specific balancing market time unit and delivered through normal activation or normal local activation, or special activation, shall be calculated for each type of the regulation product as multiplication of the activated regulation product power volume and the period recorded in the activation command within the market time unit (from the start time recorded in the activation command to the end of activation in the market time unit).

20.2 If balancing has been performed within a control zone, the regulation service fee in the market time unit for the quantity of energy purchased or sold by the transmission system operator and sold or purchased by the regulation service provider, as determined in accordance with Paragraph 20.1 of this Annex, shall be calculated for each type of activation and each regulation product as multiplication of the quantity of energy and the corresponding type of activation, and regulation product price.

21. If balancing has been performed within a coordinated balancing area, the price of a regulation product bid activated through normal activation shall be determined in accordance with the procedures laid down in the uniform balancing market rules, applying the following:

21.1. the marginal price which is equal to the highest price of an upward activated bid in the trading interval t for regulation product bids that were activated upward (towards load);

21.2. the marginal price which is equal to the lowest price of an downward activated bid in the trading interval t for regulation product bids that were activated downward (towards shedding).

21.1 If balancing is performed within a control area, the price of the relevant regulation product bid activated through normal activation shall be determined in accordance with the methodology laid down in Article 30(1) of Regulation 2017/2195.

21.2 If balancing has been performed within a control zone, the price of the relevant regulation product bid activated through normal local activation shall be determined for each regulation product in the market time unit in accordance with the procedures laid down in the balancing market rules, applying the following:

21.21. the threshold price which cannot be set lower than the price determined in accordance with Paragraph 21.1 of this Annex for the relevant regulation product bids that were activated upward (towards load);

21.22. the threshold price which cannot be set higher than the price determined in accordance with Paragraph 21.1 of this Annex for the relevant regulation product bids that were activated downward (towards shedding).

22. The price of the relevant regulation product bid activated through special activation shall be determined in accordance with the procedures laid down in the balancing market rules, applying the price determined in the relevant regulation product bid of the regulation service provider.

23. The transmission system operator shall, within two working days after the activation of the relevant regulation product bid, send to the regulation service provider a report on the relevant quantity of the regulation energy used (MWh), the applied price (EUR/MWh), and the multiplication of these values (EUR) for each 60-minute period starting on the full hour (if balancing has been performed within a coordinated balancing area) or for each 15-minute period (if balancing has been performed within a control area), separately indicating the following:

23.1. the relevant regulation products delivered through upward activation;

23.2. the relevant regulation products delivered through downward activation.

23.1 The regulation service fee in the balancing market time unit for the quantity of regulation capacity purchased by the transmission system operator and sold by the regulation service provider shall be determined in accordance with Article 33(1) of Regulation 2017/2195.

24. Mutual settlements between the transmission system operator and the regulation service provider shall be made in accordance with the procedures and time limits laid down in the ancillary service contract.

**Annex 9**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*30 May 2019; 2 March 2023; 3 October 2024*]

**Information to be Used for the Calculation of the Final Position of the Balancing Service Recipient**

1. The balancing service recipient shall provide the transmission system operator with the common schedule of the balancing service recipient that is necessary to determine the final position of the balancing service provider and to prepare the operational schedule of the system, including the following information about its imbalance area:

1.1. the planned quantity of consumed electricity in total for all the commercial accounting sites of customers included in the imbalance area of the balancing service recipient;

1.2. the planned quantity of electricity injected into the electricity system by electricity producers;

1.3. the planned trading transactions.

2. The balancing service recipient shall provide the information laid down in Paragraph 1 of this Annex in megawatts (MW) with an accuracy of one decimal place.

3. The balancing service recipient shall provide the information laid down in Sub-paragraph 1.2 of this Annex for all commercial accounting sites of electricity producers included in the imbalance area of the balancing service recipient as follows:

3.1. individually for each power plant with an installed capacity of 10 MW and more;

3.2. aggregated for all hydroelectric power stations, thermal power stations, biogas power plants, and combined heat and power plants with an installed capacity of less than 10 MW;

3.3. aggregated for all wind and solar power plants with an installed capacity of less than 10 MW.

4. The balancing service recipient shall provide the information laid down in Sub-paragraph 1.3 of this Annex as follows:

4.1. aggregated for all trading operations on the day ahead electricity market of the electricity exchange;

4.2. aggregated for trading operations between imbalance areas.

5. After the approval of the common schedule of the balancing service recipient, the balancing service recipient has the right to make changes in the following information submitted in accordance with Paragraph 1 of this Annex:

5.1. the planned quantity of electricity injected into the transmission system by electricity producers, reallocating the quantity of electricity injected into the transmission system among different power stations included in the imbalance area, without changing the planned total quantity of electricity injected into the transmission system in the corresponding imbalance settlement period;

5.2. the planned quantity of electricity injected into the transmission system by electricity producers in the corresponding imbalance settlement period if the imbalance area of the balancing service recipient includes electrical installations for both electricity generation and consumption;

5.3. trading transactions on the current day electricity market of the electricity exchange;

5.4. trading transactions between imbalance areas.

6. If the information provided by the balancing service recipient in accordance with Sub-paragraph 4.1 or 5.3 of this Annex does not correspond to the information about trading transactions on the day ahead electricity market or the current day electricity market respectively for the relevant imbalance settlement period, as provided to the transmission system operator by the electricity market operator, the balancing service recipient shall be obliged to submit specified information that corresponds to the data provided by the electricity market operator. If the balancing service recipient does not provide appropriate information or the resubmitted information does not correspond to the information provided by the electricity market operator, the transmission system operator shall use the information provided by the electricity market operator.

7. The balancing service recipient shall harmonise the information to be provided in accordance with Sub-paragraph 4.2 or 5.4 of this Annex with the information provided by all balancing service recipients involved in the relevant trading transactions. If the information provided by the balancing service recipient does not correspond to the information provided by other balancing service recipients involved in the relevant trading transactions, the balancing service recipient shall be obliged to harmonise information repeatedly and submit specified information.

8. The transmission system operator shall determine and publish on its website the time limits and procedures for submitting the information laid down in Paragraph 1 of this Annex and any changes thereto, and also the time units for which the data are to be provided.

**Annex 10**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*30 May 2019; 2 March 2023*]

**Network Connection Requirements for High-Voltage Direct Current Systems and Direct Current-Connected Power Park Modules**

1. The network connection requirements for high-voltage direct current (hereinafter – the HVDC) systems and direct current-connected power park modules (hereinafter – the DC module) shall be laid down based on Article 5(1) of Regulation 2016/1447 and shall be applicable by taking into account the requirements laid down in Regulation 2016/1447.

2. As regards to the frequency ranges, the HVDC system shall be capable of remaining connected to the network and operating within the short-circuit power range determined in accordance with Paragraph 26 of this Annex and within the following frequency ranges and periods:

2.1. 47.0–47.5 Hz for at least 60 seconds;

2.2. 47.5–48.5 Hz for at least 90 minutes;

2.3. 48.5–49.0 Hz for at least 90 minutes;

2.4. 49.0–51.0 Hz indefinitely;

2.5. 51.0–51.5 Hz for at least 90 minutes;

2.6. 51.5–52.0 Hz for at least 15 minutes.

3. It shall be permissible for the type HVDC system to have reduced maximum active power at the frequency drop below 49 Hz if the reduction rate for a frequency drop of 1 Hz is 2 % of the maximum power at the frequency of 50 Hz (Figure 1).



Fig. 1. The permissible maximum power capability reduction for the type HVDC system at a decreasing frequency,

where:

ΔΡ – active power change of the HVDC system;

Pmax – maximum active power of the HVDC system (MW);

f – network frequency (Hz).

4. The HVDC system shall conform to the following requirements which apply to the capability of controlling the transmitted active power:

4.1. it shall be capable of adjusting the active power with a delay not exceeding 100 ms;

4.2. it shall be capable of changing the active power supply with an initial delay not exceeding 10 ms since receipt of the corresponding signal from the transmission system operator in the event of disturbances in one or more alternating current networks to which it is connected. The initial delay may exceed 10 ms if, based on the reasoned justification of the HVDC system’s owner, an authorisation of the transmission system operator has been obtained for such a derogation.

5. Control functions of the HVDC system shall be capable of ensuring automatic corrective actions, including suspension of ramp-up changes and blocking of frequency sensitive mode (FSM), limited frequency sensitive mode – increased frequency (LFSM-O), limited frequency sensitive mode – decreased frequency (LFSM-U), and frequency control blocking, transmission power limitation, voltage, and reactive power control.

6. The frequency control system of the HVDC system shall provide the possibility to set starting and blocking functions by using the following starting and blocking criteria:

6.1. frequency changes;

6.2. voltage changes;

6.3. disconnection of transmission network equipment;

6.4. overload of transmission network equipment.

7. The management system of the HVDC system shall include a synthetic inertia function that ensures a rapid active power change in the event of sudden frequency changes. The synthetic inertia function of the HVDC system shall operate in accordance with the principles and settings agreed upon between the owner of the HVDC system and the transmission system operator.

8. The HVDC system shall be capable of responding to frequency deviations in the alternating current network by adjusting active power transmission, taking into account the following active power frequency response parameters in frequency sensitive mode (FSM):

8.1. frequency response deadband – 0–±500 mHz;

8.2. droop s1 (upward regulation) – 0.1–12 %;

8.2. droop s2 (downward regulation) – 0.1–12 %;

8.4. frequency response deadband shall not exceed 10 mHz.

9. As a result of abrupt changes in frequency, the HVDC system shall be capable of adjusting active power within 30 seconds, with an initial maximum delay not exceeding 0.5 seconds, as specified by the transmission system operator in the technical regulations of connection of the HVDC system (Figure 2).



Fig. 2. Active power frequency response capability of the HVDC system,

where:

ΔΡ1/Pmax – the active power change to the maximum power;

t1 – the maximum allowable initial delay (s);

t2 – the time for full activation (s).

10. The HVDC system in the limited frequency sensitive mode – increased frequency (LFSM-O) – shall be capable of activating active power frequency response capability (Figure 3) under the following conditions:

10.1. the frequency threshold shall be 50.2 Hz;

10.2. the droop setting shall be 5 %, the droop shall be adjustable within the range of 2 % to 12 %.



Fig. 3. Active power frequency response capability of the HVDC system in the limited frequency sensitive mode – increased frequency (LFSM-O),

where

fn – nominal network frequency (Hz);

Δf – change in the network frequency;

S3 – droop setting (%).

11. The HVDC system in the limited frequency sensitive mode – decreased frequency (LFSM-U) shall be capable of activating active power frequency response capability (Figure 4) under the following conditions:

11.1. the frequency threshold shall be 49.8 Hz;

11.2. the droop setting shall be 5 %, the droop shall be adjustable within the range of 2 % to 12 %.



Fig. 4. Active power frequency response capability of the HVDC system in the limited frequency sensitive mode – decreased frequency (LFSM-U),

where:

S4 – droop setting (%).

12. If the voltage has deviated from the reference voltage value, the HVDC shall be capable of operating without disconnecting from the network within the following voltage range at the connection point of the electricity transmission system and period:

|  |  |  |
| --- | --- | --- |
| Voltage value at the connection point of the transmission system | Voltage range | Period of operation |
| 110 kV | 0.85–1.118 p.u.(93.5–122.98 kV) | Indefinitely |
| 110 kV | 1.118–1.15 p.u.(122.98–126.5 kV) | 20 minutes |
| 330 kV | 0.88–1.097 p.u.(290.4–362.01 kV) | Indefinitely |
| 330 kV | 1.097–1.15 p.u.(362.01–379.5 kV) | 20 minutes |

13. As regards short-circuit contribution during faults, in the event of symmetrical (three-phase) faults, the HVDC system shall be capable of ensuring a fast fault current at the connection point under the following conditions:

13.1. the characteristic of the fast fault current – reactive current;

13.2. the initial delay for supply of the fast fault current shall not exceed 20 ms, 90 % of the fault current contribution shall be reached within 30 ms from the start of the fault, and the stabilisation time shall not exceed 60 ms from the start of the fault, with a tolerance of -5 % < Δx < +15 %.

14. As regards asymmetric current supply, in the event of asymmetric (single-phase or two-phase) faults, the HVDC system shall ensure both direct and inverse sequence currents.

15. The HVDC system shall ensure the reactive power capability of the HVDC system specified in Figure 5 in relation to the variable voltage profile at the connection point (U-Q/Pmax profile) and shall be capable of transitioning to any operating point in the U-Q/Pmax profile within not more than 60 seconds.



Fig. 5. U-Q/Pmax profile of the HVDC system,

where:

Q – reactive power;

Pmax – maximum active power;

U – voltage at the connection point;

 – U-Q/Pmax profile for 330 kV voltage;

 – U-Q/Pmax profile for 110 kV voltage.

16. Reactive power variations caused by the operation of the HVDC converter station in the control modes laid down in Paragraph 17 of this Annex may not cause a voltage leap at the connection point exceeding 2 % of the voltage value before the change.

17. The HVDC converter station shall be capable of operating in the following control modes:

17.1. voltage control mode;

17.2. reactive power control mode;

17.3. power factor control mode.

18. As regards the voltage control mode, each HVDC converter station shall be capable of assisting in the control of voltage at the connection point by using its capabilities and following Paragraphs 15 and 16 of this Annex, and also taking into account the following requirements:

18.1. after abrupt changes in voltage, the HVDC converter station shall be capable of:

18.1.1. ensuring change in the reactive output power in the amount of 90 % within the time t1 determined by the transmission system operator in the range of 0.1 to 10 seconds. The voltage control system of the HVDC converter station shall provide for a possibility to change the time t1 setting;

18.1.2. stabilising at a value determined by the operational slope within the time t2 determined by the transmission system operator in the range of 1 to 60 seconds. The voltage control system of the HVDC converter station shall provide for a possibility to change the time t2 setting. The tolerance in the steady-state mode shall be 2 % of the maximum reactive power value but not exceeding 5 MVAr;

18.2. The HVDC converter station shall be capable of changing the reactive output power by taking into account a changed setting of voltage value and a reactive power component indicated additionally by the transmission system operator. The slope shall be adjustable in the range of 1 to 10 %, with a step of 0.1 %.

19. As regards the reactive power control mode, the reactive power of the HVDC system shall range from 0 to 100 % of the maximum reactive power, with an accuracy of up to 2 % of the reactive power setting value, taking into account the technical capabilities of the HVDC converter station.

20. For the HVDC system in a low or high-voltage mode and during faults requiring fault-ride-through capability, the priority shall be given to reactive power contribution.

21. The owner of the HVDC system shall ensure that the connection of the HVDC system to the network does not cause disturbances or fluctuations in the supply voltage of the network at the connection point that exceed the threshold values specified in the standard LVS EN 50160 – Voltage Characteristics of Public Distribution Systems.

22. In the event of symmetrical or asymmetrical faults, the HVDC converter station shall be capable of remaining connected to the network and continue stable operation after electricity system has recovered following the fault clearance, taking into account the voltage-time profile specified in Figure 6.



Fig. 6. Voltage-time profile of the HVDC converter station,

where:

U (p.u.) – voltage reference value;

Uret – voltage maintained at the connection point during the fault;

Ureci – the lower limits of voltage recovery during time i after the fault clearance;

Ublock – the blocking voltage at the connection point, determined during the design stage of the HVDC system;

t – time (s);

tclear – the moment when the fault is cleared (s);

treci – the time i when the lower limits of voltage recovery are reached after the fault clearance (s).

23. After a fault, the HVDC system shall be capable of restoring the active power set previously, with an accuracy of ±10 % of the nominal power (Pnom), not exceeding 200 ms, if the voltage reference value reaches 0.9 p.u.

24. If the HVDC converter station is connected to voltage in the alternating current network or synchronised with it, the HVDC converter station shall be capable of limiting voltage changes to the steady-state mode level, taking into account the following requirements:

24.1. the level of voltage changes in the steady-state mode may not exceed 2 % of the pre-synchronisation voltage;

24.2. in the event of disturbances, if the HVDC system has been disconnected, the level of voltage changes may not exceed 5 % of the pre-synchronisation voltage;

24.3. the maximum amount of transient voltage shall be ±0.1 p.u., its duration shall be 3 s, and a measurement interval – 30 ms.

25. The HVDC system shall be capable of damping power fluctuations within a frequency range of 0.1 to 2 Hz.

26. The HVDC system shall be capable of operating within the short-circuit power range and under network characteristics specified by the transmission system operator in the technical regulations of the connection of the HVDC system.

27. If one converter station is connected to voltage, then the HVDC system with the black start capability, shall be capable of connecting voltage to the alternating current substation busbar to which another converter station is connected within one hour after the shutdown of the HVDC system. The HVDC system shall be capable of synchronising within the frequency range laid down in Paragraph 2 and within the voltage range laid down in Paragraph 12 of this Annex.

28. As regards the frequency ranges and frequency response within a system whose nominal frequency is 50 Hz, the DC module shall be capable of remaining connected to the network of the most remote HVDC converter station and operating within the following frequency ranges and periods:

28.1. 47.0–47.5 Hz for at least 20 seconds;

28.2. 47.5–49.0 Hz for at least 90 minutes;

28.3. 49.0–51.0 Hz indefinitely;

28.4. 51.0–51.5 Hz for at least 90 minutes;

28.5. 51.5–52.0 Hz for at least 15 minutes.

29. The DC module shall be capable of remaining connected to the network of the most remote HVDC converter station and operating within the following voltage range at the direct current connection point and period:

|  |  |  |
| --- | --- | --- |
| Voltage value at the connection point of the direct current system | Voltage range | Period of operation |
| 110 kV–300 kV (excluding) | 0.85–0.90 p.u. | 60 minutes |
| 110 kV–300 kV (excluding) | 0.90–1.10 p.u. | Indefinitely |
| 110 kV–300 kV (excluding) | 1.10–1.118 p.u. | Indefinitely |
| 110 kV–300 kV (excluding) | 1.118–1.15 p.u. | 20 minutes |
| 300 kV–400 kV (excluding) | 0.85–0.90 p.u. | 60 minutes |
| 300 kV–400 kV (excluding) | 0.90–1.05 p.u. | Indefinitely |
| 300 kV–400 kV (excluding) | 1.05–1.15 p.u. | 20 minutes |

30. As regards to the voltage stability and reactive power capability, the DC module, at the maximum HVDC active power transmission capacity, shall ensure the reactive power capability of the DC module specified in Figure 7, in relation to the variable voltage profile at the connection point (U-Q/Pmax profile).



Fig. 7. U-Q/Pmax profile of the DC module,

where:

Q – reactive power;

Pmax – maximum active power;

U – voltage at the connection point;

 – U-Q/Pmax profile for 300 kV–400 kV (including) voltage;

 – U-Q/Pmax profile for 110 kV–300 kV (excluding) voltage.

31. For the DC module in a low or high voltage mode and during faults requiring fault-ride-through capability, the priority shall be given to reactive power contribution.

32. When the DC module synchronises with the alternating current collector network, it shall be capable of limiting voltage changes to the steady-state mode level, taking into account the following requirements:

32.1. the level of voltage changes in the steady-state mode shall not exceed 2 % of the pre-synchronisation voltage;

32.2. in the event of disturbances, if the HVDC system has been disconnected, the level of voltage changes may not exceed 5 % of the pre-synchronisation voltage;

32.3. the maximum transient voltage shall be ±0.1 p.u., its duration shall be 3 s, and a measurement interval – 30 ms.

33. The DC module shall be capable of operating within the short-circuit power range and under network characteristics specified by the transmission system operator in the technical regulations of the connection of the DC module.

34. The owner of the DC module shall ensure that the connection of the DC module to the network does not cause disturbances or fluctuations in the supply voltage of the network at the connection point that exceed the threshold values specified in the standard LVS EN 50160 – Voltage Characteristics of Public Distribution Systems.

35. The DC module shall meet the requirements laid down in Paragraphs 10 and 17 of Annex 7 to this Code.

36. The most remote HVDC converter station shall be capable of remaining connected to the network of the most remote HVDC converter station and operating within the voltage range and periods laid down in Paragraph 29 of this Annex.

37. As regards the capability of ensuring reactive power, the most remote HVDC converter station shall ensure the U-Q/Pmax profile specified in Figure 7.

**Annex 11**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*30 May 2019; 2 March 2023; 3 October 2024*]

**Network Connection Requirements for Customers in the Electricity Transmission System**

1. The network connection requirements for customers in the electricity transmission system shall be laid down based on Article 6(1) of Regulation 2016/1388 and shall be applicable in accordance with the requirements laid down in Regulation 2016/1388.

2. A demand facility connected to the transmission system, a distribution facility connected to the transmission system, and a distribution system shall be capable of remaining connected to the network and operating within the following frequency ranges and periods:

2.1. 47.5–48.5 Hz for at least 30 minutes;

2.2. 48.5–49.0 Hz for at least 30 minutes;

2.3. 49.0–51.0 Hz indefinitely;

2.4. 51.0–51.5 Hz for at least 30 minutes.

3. A demand facility connected to the transmission system, a distribution facility connected to the transmission system, and a distribution system connected to the transmission system shall be capable of remaining connected to the network and operating within the following frequency ranges and periods:

|  |  |  |
| --- | --- | --- |
| Synchronous zone, voltage value at the connection point | Voltage range | Period of operation |
| The Baltics, 110 kV | 0.90–1.118 p.u.(99.0–122.98 kV) | Indefinitely |
| The Baltics, 110 kV | 1.118–1.15 p.u.(122.98–126.5 kV) | At least 20 minutes |
| The Baltics, 330 kV | 0.90–1.097 p.u.(297.0–362.01 kV) | Indefinitely |
| The Baltics, 330 kV | 1.097–1.15 p.u.(362.01–379.5 kV) | At least 20 minutes |

4. A distribution system connected to the transmission system whose voltage at the connection point is lower than 110 kV shall be capable of remaining connected to the network and operating within the following frequency ranges and periods:

|  |  |  |
| --- | --- | --- |
| Voltage value at the connection point | Voltage range | Period of operation |
| 6 kV | 0.85–1.1 p.u.(5.1–6.6 kV) | Indefinitely |
| 6 kV | 1.1–1.2 p.u.(6.6–7.2 kV) | At least 3 minutes |
| 10 kV | 0.85–1.1 p.u.(8.5–11.0 kV) | Indefinitely |
| 10 kV | 1.1–1.2 p.u.(11.0–12.0 kV) | At least 3 minutes |
| 20 kV | 0.85–1.1 p.u.(17.0–22.0 kV) | Indefinitely |
| 20 kV | 1.1–1.2 p.u.(22.0–24.0 kV) | At least 3 minutes |

5. When operating a demand facility, a distribution facility, or a distribution system, the owner of the demand facility connected to the transmission system and the operator of the distribution system connected to the transmission system shall take into account the maximum short-circuit current at the connection point determined in the system service contract which the demand facility connected to the transmission system or distribution system connected to the transmission system must be able to withstand.

6. A demand facility connected to the transmission system shall be capable of maintaining operation in the steady-state mode at its connection point within the actual reactive power range of up to 48 % of its maximum import capacity or export capacity, depending on which is greater (the active power factor for import or export shall not be less than 0.9).

7. A distribution system connected to the transmission system shall be capable of maintaining operation in the steady-state mode at its connection point within the following actual reactive power ranges:

7.1. during the reactive power import (consumption) – up to 48 % of the maximum import capacity or maximum export capacity, depending on which is greater (the power factor shall not be less than 0.9);

7.2. during the reactive power export (production) – up to 48 % of the maximum import capacity or maximum export capacity, depending on which is greater (the power factor shall not be less than 0.9).

8. Equipment of the demand facility connected to the transmission system and equipment of the distribution system connected to the transmission system shall be equipped with relay protection and automation devices that, depending on the installation location, shall respond to the following disturbances:

8.1. short-circuit;

8.2. unacceptable current overload of the equipment;

8.3. non-full-phase operating mode;

8.4. unacceptable overexcitation of transformers and auto transformers (U/f function);

8.5. unacceptable overvoltage;

8.6. asynchronous operation with the transmission network;

8.7. unacceptable load current asymmetry.

9. Equipment of the demand facility connected to the transmission system and equipment of the distribution system connected to the transmission system shall be equipped with primary relay protection and backup relay protection devices. Devices which, without a time delay, protect the connected connection from various types of short-circuits therein or which are the only protection of the connection for a specific type of fault shall be considered primary relay protection devices. To the extent technically feasible, backup relay protection devices of the connection shall provide the functions of primary relay protection device for its connection, and also, following the selective operational principle laid down in Paragraph 11 of this Annex, reserve the primary and backup relay protection devices of adjacent network connections in the event of their failure.

10. A demand facility connected to the transmission system and a distribution system connected to the transmission system shall be equipped with automation devices that ensure automatic shedding according to frequency and automatic shedding according to voltage, with automatic re-activation of the device once frequency and voltage are restored. The owner of a demand facility connected to the transmission system and the operator of a distribution system connected to the transmission system shall ensure the settings of automation devices and the volumes of load to be disconnected in accordance with an agreement with the transmission system operator.

11. The transmission system operator and the owner of a demand facility connected to the transmission system or the operator of a distribution system connected to the transmission system shall coordinate the settings and effects of relay protection and automation devices in order to ensure that their operation is mutually selective in the event of the disturbances laid down in Paragraph 8 of this Annex.

12. If it is not technically feasible to coordinate the selective operation of a specific relay protection device with the relay protection devices of connections of adjacent electricity network, the owner of the demand facility connected to the transmission system or the operator of the distribution system connected to the transmission system shall envisage a technically feasible solution within its system to correct the non-selective operation of the relay protection device – automatic re-activation, automatic backup activation, automatic splitting of the electricity network followed by automatic re-activation, command transmission to other facilities, or another solution. Owners of the equipment connected to the connection point of the transmission system shall mutually coordinate the settings of relay protection and automation devices, mutually exchanging data on the settings of relay protection and automation devices upon request.

13. Relay protection devices for a demand facility connected to the transmission system and a distribution system connected to the transmission system shall, without a time delay, disconnect short-circuits that cause a deterioration in the effective value of phase or interphase voltage at the connection point of the transmission system to 0.6 Unom or lower. In the event of a failure of a circuit breaker, relay protection devices shall disconnect short-circuits for not longer than 0.25 s.

14. 110 kV and 330 kV circuit breakers of equipment at the connection point of the transmission system and medium- and low-voltage circuit breakers of transformers and auto transformers shall be equipped with breaker failure protection with an actuation time setting of not more than 0.15 s.

15. The settings of relay protection devices shall ensure the thermal stability of equipment of the connection point of the transmission system in the event of short-circuits, prevent overexcitation (voltage/frequency parameter) that exceed the permissible overexcitation determined for transformers and auto transformers, and disconnect the equipment if the current overload exceeds the permissible current overload limit determined for the equipment.

16. As regards demand disconnection at low frequency, a demand facility connected to the transmission system and a distribution system connected to the transmission system shall be equipped with a device functionally capable of automatically disconnecting 100 % of the actual load at reduced frequency and with a disconnection trigger based on low frequency, as well as a combination of low frequency and rate of change of frequency. The demand disconnection device shall envisage a possibility for changing the activation settings within a range of 47 to 50 Hz with a step not exceeding 0.05 Hz, facilitate load disconnection by steps, and activate the demand disconnection function for the disconnection of at least 65 % of the actual load of demand facilities. The owner of the demand facility connected to the transmission system and the operator of the distribution system connected to the transmission system shall ensure the settings and effects of the demand disconnection device, in respect of which an agreement has been reached with the transmission system operator and which shall be specified by the transmission system operator in setting maps of the relay protection and automation equipment.

17. As regards the functional capabilities of disconnecting demand at low voltage, a demand facility connected to the transmission system and a distribution system connected to the transmission system shall be equipped with a device functionally capable of automatically disconnecting 100 % of the actual load at low voltage. The device shall activate the demand disconnection function for the disconnection of at least 65 % of the actual load of demand facilities if the voltage at the connection point of the transmission system is below 0.9 p.u. The owner of the demand facility connected to the transmission system and the operator of the distribution system connected to the transmission system shall ensure the settings and effects of the demand disconnection device, in respect of which an agreement has been reached with the transmission system operator and which shall be specified by the transmission system operator in setting maps of the relay protection and automation equipment.

18. As regards to the capability to reconnect after disconnection or disconnect, a demand facility connected to the transmission system and a distribution system connected to the transmission system may automatically reconnect when the frequency at the connection point of the transmission system is within the range of 49.0 Hz to 51.0 Hz, and the voltage at the connection point is within the range that corresponds to the period of operation “indefinitely” laid down in Paragraphs 3 and 4 of this Annex within the time setting determined by the transmission system operator. The demand facility connected to the transmission system and the distribution system connected to the transmission system shall be remotely disconnected for not more than 500 ms.

19. The owner of the demand facility connected to the transmission system and the operator of the distribution system connected to the transmission system shall ensure that the connection of the demand facility or distribution system to the network does not cause disturbances or fluctuations in the supply voltage of the network at the connection point that exceed the threshold values specified in the standard LVS EN 50160 – Voltage Characteristics of Public Distribution Systems.

20. A demand unit that provides a demand response for active power control, a demand response for reactive power control, or a demand response for overcoming transmission limitations shall, individually or, if the unit is not part of a demand facility connected to the transmission system, collectively as part of a demand unit established by a third party, meet the following requirements:

20.1. it shall be capable of operating within the voltage ranges laid down in Paragraphs 3 and 4 of this Annex;

20.2. it shall be capable of adjusting its power consumption within the period laid down in the balancing market rules;

20.3. as regards the withstand capability of rate of change of frequency, it shall be capable of remaining connected to the network and operating until the protection against network voltage loss is activated. Rate of change of frequency protection with an activation setting of 2.5 Hz/s shall be used for the protection against network voltage loss. The measurement interval shall not exceed 500 ms.

21. The owner of the demand facility connected to the transmission system shall immediately inform the transmission system operator of any modifications to the demand facility that affect the demand response capability.

22. For a demand unit that ensures a demand response for the frequency control of the system:

22.1. frequency response deadband shall be ±200 mHz;

22.2. the maximum frequency deviation to which it shall respond is -1.0 Hz and +1.5 Hz from the nominal value of 50.00 Hz.

**Annex 12**

Decision No. 1/4 of the Public Utilities Commission

26 June 2013

[*5 December 2019; 2 March 2023; 3 October 2024*]

**Regulations Regarding the Suspension, Restoration of Market Operations, and Imbalance Settlements During the Suspension of Market Operations and Settlements During the Implementation of Controlled Dispatch Control**

1. The regulations shall determine the suspension, restoration of market operations, imbalance settlements, and settlements for balancing electricity that are applicable to imbalance settlement periods during which market operations were suspended, based on Article 36(1) and Article 39(1) of Regulation 2017/2196, ans also the settlements during the implementation of controlled dispatch control.

2. Prior to taking the decision to suspend the market operation, the transmission system operator shall carry out the necessary activities in order to ensure the continuation of the relevant market operation as much as possible and shall assess in real time whether one or more of the following conditions are present in the transmission system:

2.1. a complete loss of voltage for at least three minutes;

2.2. electricity consumption is 50 % lower than the planned consumption, and therefore:

2.2.1. it is not possible to ensure the balance of the electricity system;

2.2.2. it is not possible to activate other electricity sources, including to receive ancillary services from service providers outside the control zone of the transmission system operator;

2.3. volume of electricity generation is 75 % lower than the planned volume within the frequency control zone of the transmission system operator, and the frequency in the range of 49.0 to 48.0 Hz;

2.4. a different frequency (∆f ≥ 50 mHz) has been identified at the same voltage level in three or more substations of the transmission system;

2.5. the primary and backup means of communication required for ensuring the market processes (e-mail systems, data exchange services, data transmission networks, voice communications, and others) have been unavailable for more than 30 minutes.

3. If the transmission system operator establishes the presence of any condition specified in Paragraph 2 of this Annex and, after evaluation thereof, takes the decision to suspend the market operation, the transmission system operator shall send a notification to the addressees specified in Paragraph 6 of this Annex by using any of the means of communication available to the transmission system operator, and include at least the following information in its notification:

3.1. the date and time of the suspension of the market operation;

3.2. the market operation that is being suspended;

3.3. the time when controlled dispatch control is commenced;

3.4. the possible time for the restoration of the suspended market operation.

4. During the time period when a market operation is suspended, the distribution system operators, significant customers in the network, and restoration and defence service providers shall be obliged to comply with an order of dispatcher of the transmission system operator in accordance with the system defence plan and the system restoration plan.

5. When restoring the suspended market operation, the transmission system operator shall send a notification by using any of the means of communication available to the transmission system operator, and include at least the following information in its notification:

5.1. the time when the market operation will be restored;

5.2. the restoration of operational tools of the market and means of communication of other market participants;

5.3. the time when the balancing service recipient must submit to the transmission system operator the common schedule of the balancing service recipient for the next day laid down in Paragraph 1 of Annex 9 to this Code.

6. The transmission system operator shall publish the notifications laid down in Paragraphs 3 and 5 of this Annex on its website and send them to the following addressees:

6.1. the distribution system operator whose system is connected to the transmission network;

6.2. the defence service provider;

6.3. the restoration service provider;

6.4. the balancing service provider;

6.5. the electricity market operator;

6.6. the regulator;

6.7. the regulation service provider;

6.8. the significant customer in the network;

6.9. the regional security coordinator;

6.10. the merchant performing the functions of the platform for granting unified long-term transmission rights;

6.11. the transmission system operators of the Baltic capacity calculation region.

7. The transmission system operator shall include the quantity of balancing electricity activated within framework of the controlled dispatch control in the calculation of the imbalance of the used reserve provision unit of the balancing service provider as an imbalance correction.

8. If controlled dispatch control is implemented during the suspension of the balancing market, the transmission system operator and the market participant shall make mutual settlements, taking into account the following conditions:

8.1. for the quantity of electricity injected into the transmission system within the framework of controlled dispatch control, the transmission system operator shall settle with the market participant according to the price justified by the costs of the market participant incurred in providing the service to the transmission system operator within the framework of controlled dispatch control;

8.2. for the quantity of electricity received from the transmission system within the framework of controlled dispatch control, the market participant shall settle with the transmission system operator in accordance with the price that corresponds to the costs of the electricity received within the framework of controlled dispatch control;

8.3. imbalance settlements within the framework of controlled dispatch control shall be made by replacing the imbalance price in the determination of the imbalance fee with the price that corresponds to the costs of the electricity received within the framework of controlled dispatch control.

9. If controlled dispatch control is implemented during the period when the balancing market is not suspended, the transmission system operator and the market participant who has not entered into an ancillary service contract or who has not submitted a regulation product bid in the relevant balancing market time unit for the provision of regulation service shall make mutual settlements, taking into account the following conditions:

9.1. for the quantity of electricity injected into the transmission system within the framework of controlled dispatch control, the transmission system operator shall settle with the market participant according to the price justified by the costs of the market participant incurred in providing the service to the transmission system operator within the framework of controlled dispatch control;

9.2. for the quantity of electricity received from the transmission system within the framework of controlled dispatch control, the market participant shall settle with the transmission system operator in accordance with the price that corresponds to the costs of the electricity received within the framework of controlled dispatch control;

9.3. imbalance settlements within the framework of controlled dispatch control shall be made in accordance with the provisions of Chapter 4.12 of this Code.

10. Settlement parties shall attach information about settlements within the framework of controlled dispatch control to the monthly invoice.