BULGARIAN GRID CODE

Chapter One

GENERAL PROVISIONS

Art. 1. (1) The Grid Code regulates the rights and responsibilities of the transmission enterprise; the PS operator; electricity generators; customers connected to the transmission system; the public provider; public suppliers and electricity traders, in relation to planning the transmission system development, scheduling and control of PS operating mode; procedures of mandatory data interchange, sequence of on-line data interchange; development and performance of a defense plan and of a plan for PS restoration; conditions and procedure of system tests; provision of complementary services, and other activities related to the overall PS operation process.

(2) The relations of the transmission enterprise with external (foreign) partners are regulated by:

1. Agreements for parallel operation within the synchronous zone;
2. Other joint operation agreements.

Art. 2. The main objectives of the Grid Code are to create prerequisites for:

1. Reliability and good quality of customers supply with electricity;
2. Efficient development of the transmission system and generating capacities in Bulgaria;
3. Conditions for participation of transmission system Users in the electricity market on equal treatment conditions and with guarantees for reliability and high-quality operation of the EPS.

Art. 3. (1) This Grid Code defines:

1. the procedures of transmission system development planning;
2. technical requirements for connection to the transmission system;
3. procedures of transmission system use;
4. procedures of PS operation planning;
5. procedures of on-line PS control;
6. activities of the PS operator and of transmission system Users related to the quality control of PS operation;
7. EPS test procedures.

(2) The procedures are defined:

1. so as to guarantee reliable, safe and efficient operation of the PS and uninterrupted power supply to the consumers;
2. taking into account the technical requirements of the Union for Coordination of Transmission of Electricity (UCTE) in relation to reliability and quality of the parallel operation of power systems;
3. the PS operator has the right to expand the scope of technical requirements towards Users within the framework of their existing technical capabilities in order to guarantee

reliable, safe and efficient functioning of the power system and uninterrupted supply of the customers with electricity in normal mode and in the event of disturbances;

4. the PS operator has the right to make and implement decisions in the event of conflict between the requirements of electricity market players and the need to maintain the needed level of reliability, safety and quality of PS operation;

5. taking into account the organizational and technical requirements that guarantee the conditions of PS restoration after severe accidents with the least possible risk to human lives and health, in the event of environmental pollution, economic damages and social tension;

6. with respect for the principle of equal treatment and non-discriminatory attitude towards the transmission system Users;

7. with respect for the requirements and conditions of access to the transmission system and for development of a liberalized electricity market.

Chapter Two

TRANSMISSION SYSTEM DEVELOPMENT PLANNING

Section I

General

Art. 4. (1) The Rules of planning the development of the transmission system determine the technical planning criteria, flows and volumes of the information interchanged between the transmission service provider and transmission system Users for the purposes of planning, as well as the procedures applied.

(2) The planning criteria for transmission system development shall be observed by all transmission system Users in the process of planning the development of their own electric power networks.

Art. 5. The transmission system shall be planned with a sufficient time horizon so that all required steps for coordination, design, construction and commissioning of the planned facilities could be performed without disturbing the normal operation of the power system.

Art. 6. The development of the transmission system includes construction and refurbishment of:

1. power lines;

2. transformer capacities;

3. substations and compensating devices for the purposes of voltage regulation in the transmission system;

4. auxiliary networks and control systems.

Section II

Objectives and Scope of Planning

Art. 7. Planning of transmission system development shall assure timely and harmonized construction and commissioning of new network components whereby a cost-saving and reliable operation of the power system can be assured while observing the reliability criteria indicated in Art. 12 and the prevailing standards of power supply quality.

Art. 8. The transmission system development plan shall indicate the new components that have to be built, their main technical characteristics, their location within the transmission system, terms and conditions of their commissioning.

Section III

Planning Procedure

Art. 9. (1) In conformity with the obligations arising from the Law on Energy (LoE) and the license issued, the transmission service provider shall develop and present a five-year plan of transmission system development. Such plan shall be updated every year.

(2) The transmission system development plan is a document describing the future modifications and development of the transmission system. It shall define the expected performance of the transmission system by years.

(3) The planning process shall provide for the time needed to prepare the designs and proposals from different stakeholders in a non-discriminating manner.

Art. 10. The plan shall indicate those points of the power grid that are best suited for construction of new connections for future power transmission with a view to promotion of competition and development of the transmission system.

Art. 11. The plan shall contain information about the operating parameters of the transmission system:

1. transmission capacity by main directions;
2. power flows at maximum load on the power system;
3. load in the points of connection of the transmission system Users;
4. levels of short-circuit currents in 750 kV, 400 kV, 220 kV and 110 kV buses of the substations;
5. transmission and transformation losses of power and energy in the power grid under maximum load upon the power system;
6. suggestions for transmission system development and/or changes of topology;
7. scheduled power interchanges with external (foreign) partners;
8. proposals for construction of new interconnection power lines.

Art. 12. (1) In the process of operation in a normal operating mode the transmission system shall meet the “n - 1” which means that:

1. disconnection on any power grid component (power line, transformer unit, generation set or compensating device) as well as any component group of the power grid (busbars in a high-voltage switchgear, etc.) that can be simultaneously switched off by the action of a single protection device or by the action of several protection devices as a result of one single-mode failure, should not result in:

a) interruption of supply to electricity consumers;

b) overload of the power grid components remaining in operation;

c) deterioration of electricity supply quality;

d) reduction of the stability margin;

e) disruptions in the operating mode of neighboring power systems in parallel to which the Bulgarian PS operates;

2. disconnection of a double power line laid on a common line of poles is considered as a single-mode event.

(2) The reliability criterion "n - 2" shall be applied upon connection of a nuclear power plant to the transmission system.

Art. 13. The power grid configuration should allow performance of scheduled maintenance of the facilities without violation of the reliability criteria indicated in Art. 12.

Art. 14. Reporting on the reliability criteria shall be done on the basis of a comparative engineering economic analysis of the following factors:

1. probability of a certain type of accident;
2. consequences of such type of accident;
3. costs required to cover the permanent risk;
4. cost of the protection measures against development of the accident.

Art. 15. The transmission system development plan shall be approbated by the Ministry of Energy and Energy Resources (MEER) after which it is submitted to the State Energy Regulatory Commission (SERC) and promulgated in order to make it accessible to all existing and potential Users of the power transmission system.

Section IV

Information Provision and Interchange for Planning Purposes

Art. 16. The transmission service provider shall develop the plans for development of the power transmission system on the basis of the following information:

1. Electric load development forecasts and electricity demand forecasts from the individual distribution companies up to the connection points;
2. notifications from customers connected to the transmission system;
3. new electricity consumers connected to the transmission system;
4. notifications from electricity generators for changes in their generating capacities;
5. new electricity generators connected to the transmission system;
6. notifications received from distribution companies;
7. plans of electricity interchange with other EPS's.

Art. 17. (1) The information listed in Art. 16 is supplied to the transmission service provider by Users of the part of the transmission system related to their activity.

(2) The information about demand or generation capacities of transmission system Users may be of a commercial nature and shall be used for power flow forecasts only subject to an connection contract signed between the transmission service provider and the respective User.

Chapter Three

CONNECTION TO THE TRANSMISSION SYSTEM

Section I

General

Art. 18. The main purpose of the Rules of Connection to the Transmission system is to assure:

1. The required reliability, safety and quality of PS operation after connection of the respective User;

2. Opportunity for the transmission service provider to meet its license obligations for transmission of electric power through setting technical, design and operation requirements to Users upon the latter's connection to the transmission system.

Art. 19. The initial connection of an User to the transmission system as well as increase of the required capacity made available (for a customer) or increase of the installed capacity (for a generator) of an connected User is allowed if:

1. the User has met the requirements contained in the Ordinance on Electricity Generators and Consumers to Transmission and Distribution Power grids;

2. compliance with the technical, design and operation requirements contained in the prevailing regulations and rules of transmission system operation on the part of the Users applying for connection to the transmission system.

Section II

Technical Parameters of the Transmission system

Art. 20. (1) Candidates for connection to the transmission system shall be familiar with the ratings and permissible limits of the main technical parameters maintained in the power grid.

(2) The rated voltages in the transmission system are 110 kV, 220 kV, 400 kV, and 750 kV. The limit deviations under normal operating mode are as below:

Rated voltages	**Limit deviations**
110 kV	99 kV $\leq U \leq$ 126 kV
220 kV	198 kV $\leq U \leq$ 242 kV
400 kV	380 kV $\leq U \leq$ 420 kV
750 kV	712 kV $\leq U \leq$ 787 kV

(3) The voltage levels maintained in the individual nodes of the transmission system are determined and regulated by the PS operator.

(4) The transmission service provider and the Users shall select the PS facilities and the site connection facilities in such a manner that voltage fluctuations in the event of short circuits and/or switching transients and the expected atmospheric overvoltages should not affect their normal operation.

Art. 21. The rated frequency of the power system is 50,0 Hz. Deviations from the rated value are allowed within the range 49,5 Hz to 50,5 Hz in normal operating mode. After of first and second synchronous zones the range applicable for UCTE will be adopted.

Art. 22. (1) The transmission system operates with a directly earthed star point.

(2) The manner of star point earthing in the facilities of transmission system Users is determined by the PS operator in accordance with the technical characteristics of the transmission system and of the User's facilities.

Art. 23. For the needs of design, selection of facilities and operating modes, the transmission service provider shall give the Users specialized technical information on:

1. load flows (study of established operating modes);

2. three-phase short circuit critical opening times in transient stability conditions;

3. short-circuit currents in the connection point;

4. power system equivalent impedances in the connection point;

5. selection of over voltage protection and insulation coordination.

Art. 24. (1) The property boundary between electrical facilities of the transmission service provider and those of Users is determined by the manner of connection and by the type of facilities in the connection point.

(2) In the case of connecting an User's electric switchgear to the transmission system by means of power lines – property of the transmission service provider, irrespective of the voltage level, the property boundary is:

1. in the case of cable line – the point of connection of the cable shoes to the switchgear;

2. in the case of overhead power line and indoor switchgear – the terminals for connection of the power line wires to the transformer bushings for penetration through the external walls of the switchgear;

3. in the case of overhead power line and switchyard – the terminals for connection of the wires to the power grid.

(3) A power plant can be connected to the transmission system by one of the following methods:

1. by means of power lines (overhead or cable lines), transformers or isolated phase buses – property of the power plant owner to the electrical switchgear of the transmission service provider;

2. by means of an electrical switchgear – property of the power plant, to power lines (overhead or cable lines), transformers or isolated phase buses – property of the transmission service provider.

(4) The property boundary between the electrical facilities of the transmission service provider and a power plant is determined depending on the manner of connection to the transmission system, as below:

1. in the case of cable power line – the point of connection of the cable shoes to the switchgear;

2. in the case of overhead power line and indoor switchgear – the terminals for connection of the power line wires to the transformer bushings for penetration through the external walls of the switchgear;

3. in the case of overhead power line and switchyard – the terminals for connection of the wires to the switchgear facilities;

4. in the case of a transformer – the terminals closest to the switchgear by means of which the transformer is connected to it;

5. in the case of isolated phase bus - the terminals closest to the switchgear by means of which the isolated phase bus is connected to it.

Section III

Technical Requirements to User Connection

Art. 25. In the process of active energy consumption, it is not allowed to exceed the permissible limit load on any component of the power lines or the power supply substation – property of the transmission service provider.

Art. 26. (1) The PS operator sets requirements to the customers who influence the reliability of PS operation and its capability for restoration, and are needed for implementation of the defense plan and the restoration plan.

(2) The customers shall accept and perform:

1. automatic underfrequency load shedding (UFLS) upon emergency frequency drop in the power system;

2. automatic load shedding upon emergency trip of large unit generating capacities;

3. participate in restoration paths after system accidents.

(3) The maximum limit loads on the power lines, the capacities at the different UFLS steps, shedding volume and configuration of the restoration paths are set by the PS operator and agreed upon in the contract signed between the transmission service provider and a customer pursuant to Art. 62.

Art. 27. (1) A customer shall use electric power with power factor cos $\varphi \geq 0{,}90$ unless specified otherwise in the contract between the transmission service provider and the customer.

(2) The readings of commercial metering devices shall be used to determine the actual power factor.

Art. 28. (1) The customers shall apply the needed measures to maintain a relatively permanent power in the electricity consumption during normal operation.

(2) The variation rate of consumed active power per minute in percentage of the maximum load shall not exceed 10% of P_{max} for installed capacities exceeding 50 MVA.

(3) When a customer lacks the technical capacity to meet the requirement under para. 2, the contract between the transmission service provider and the customer under Art. 62 shall provide for a control service that shall be performed by the PS operator.

Art. 29. (1) The total sum of effective values of the higher harmonic components in the current to a customer shall not exceed 5% of the effective value of the component with base frequency (50 Hz) in the connection point according to BDS EN 50160.

(2) The asymmetry of voltages in the three-phase network brought in by the customer and manifested as non-uniformity of the effective values of phase voltages or phase angle differences shall not lead to reverse-sequence voltage of a value higher than 2% of the rating.

Art. 30. (1) For customers with installed capacity larger than 50 MVA, the maximum deviation of reactive power instantaneous value from the mean value over a 15-minute time interval shall not exceed 10 MVAr.

(2) In cases where the customers' technological process involves reactive power fluctuations exceeding those indicated in para. 1, such customers shall install controllable

compensating devices in their electrical switchgears to prevent the fluctuations of active and reactive power flows and interferences in the operating mode of other transmission system Users.

(3) When it is technically impossible for a customer to meet the requirement under para. 2, the contract between the transmission service provider and the customer under Art. 62 shall provide for a regulation service to be rendered by the PS operator.

Art. 31. (1) When a customer consumes electricity from the transmission system through a transformer with automatic voltage regulation, automatic regulation blocking shall be assured upon reaching certain voltage minimums at the primary side of the transformer.

(2) The voltage level under para. 1 shall be set by the PS operator.

Art. 32. The PS operator**,** the transmission service provider and the customers shall use an unified system approved by the PS operator to designate all facilities in the connection points, thus guaranteeing reliable and safe operation of the power system.

Art. 33. (1) The volume and organization of the relay protections of transformers, buses and power lines owned by a customer shall meet the requirements of the Regulation on Design of Electrical switchgears and Power Lines.

(2) The impedance, current and operation time settings of short-circuit relay protections in the power system (external to the customer's electrical facilities) shall be mandatorily coordinated with the PS operator before their connection.

(3) Customers may be connected to the transmission system in four ways:

1. The customer is coupled, by means of its coupling devices, to a switchgear – property of the transmission service provider, i.e., the connection point is located in a transmission system substation at the beginning of a line owned by the customer;

2. A switchgear – property of the customer has been coupled to the transmission system by means of power lines – property of the transmission service provider, i.e., the connection point is located in a substation owned by the customer at the end of the transmission service provider's power line;

3. the customer is coupled through its own transformer to a substation in the transmission system, i.e., the connection point is in a substation owned by the transmission service provider at the primary side of the transformer – property of the customer;

4. the customer is coupled to the secondary side of a transformer – property of the transmission service provider, i.e., the connection point is at the secondary side of the transformer.

The requirements with respect to relay protection and automatic devices for the four manners of connection are stated generally, and any possible differences – individually.

Art. 34. (1) The relay protections of the customer's ties to the PS shall meet the standards, regulations and procedures prevailing in the country.

(2) The electrical facilities shall be protected by main and standby relay protections acting independently.

(3) In the case of 220 kV or higher-voltage power lines and interconnection power lines, the relay protection organization is based on the principle of "full local backup" pursuant to the Regulation on Design of Electrical switchgears and Power Lines, where one of the protections shall be of a distance type.

(4) For the purpose of connection to networks with directly earthed star point, additional directional three-stage overcurrent earth-fault protection with current-independent time delay shall be provided for the power lines.

(5) In any case, with main relay protection operation (first-zone, first-stage differential protection) the power line shall be disconnected from the supply side for a time not exceeding 150 ms, inclusive of the breaker time.

(6) The following measures are allowed subject to coordination with the PS operator:

1. In the event of connection under Art. 33, para. 3 items 1 & 2 to 110 kV power lines operating in parallel with the power system, the relay protection shall consist of one distance and one three-stage directional earth-fault protection with current-independent time delay;

2. In the event of connection under Art. 33, para. 3 items 1 & 2 to 110 kV and 220 kV power lines supplying a radial load (unilaterally supplied line) the relay protection shall be set up at the supply end only, by means of an overcurrent sector, an overcurrent protection and earth-fault protection with current-independent time delay.

(7) In the event of connection under Art. 33, para. 3 item 3, the type, volume and organization of transformer relay protections are subject of a design agreed upon with the transmission service provider with a view to compatibility with the existing devices.

(8) In the event of connection under Art. 33, para. 3 item 4, the type, volume and organization of the relay protections of facilities coupled to the secondary side of the transformer are subject of a design agreed upon with the transmission service provider with a view to compatibility with the existing facilities and achievement of relay protection selectivity.

(9) The reliability of relay protection operation shall not be less than 99% determined as relationship of successful breaker opening operations to the total number of faults.

Art. 35. (1) The availability and type of automatic reclosing (AR) – single-phase, three-phase, synchronism control or absence of tension for the power lines connecting the customers' switchgears with the power system is a subject of agreement between the customer and the PS operator on the basis of calculations and requirements for reliability of electricity supply.

(2) The specific settings of the AR device are determined and performed in coordination with the PS operator.

Art. 36. The technical parameters and AR settings are determined and assigned by the PS operator.

Art. 37. (1) For connection under Art. 33, para. 3, items 1 & 2 for power lines and plants – property of the customer and operating in parallel with the power system, as well as for radially supplied customers with high reliability requirements, for the purpose of accident localization in the event of failure of a breaker participating in the connection between the customer and the EPS, a circuit breaker fault protection device (BFP) is used for automatic opening of all breakers adjacent to the breaker that has failed to open.

(2) The need for a BFP is agreed upon with the PS operator on the basis of stability calculations.

(3) The device is designed on the "Breaker BFP" principle.

(4) The installation, commissioning and maintenance of a BFP is obligation of the owner of the facility where it is implemented.

(5) The particular settings and effect of a BFP are determined jointly with the PS operator.

Art. 38. (1) For power lines connecting the customer and operating in parallel with the power system at a voltage level 110 kV or higher, it is mandatory to provide a signal transmitter for acceleration (joint operation) of the relay protections at both ends of the tie line.

(2) As required, the interested parties shall agree upon the automatic distance opening of a breaker in adjacent electrical switchgear in the event of BFP operation.

(3) The specific technical solutions are the subject of a design and shall be agreed upon with the PS operator keeping in mind that the signal transmission time shall not be longer than 20 ms.

Art. 39. (1) The relay protection settings in the customer's switchgears shall be defined and proposed in the design, and shall be finalized and agreed upon before the start of operation with the PS operator on the basis of updated calculations.

(2) The settings of relay protections on the tie lines between the customer's electrical switchgears and the power system shall be determined by the PS operator.

(3) Settings of the relay protections and automatic devices installed in the customer's switchgears are mandatory and shall be performed by the customer.

Art. 40. For the purpose of PS dispatching, it is mandatory to assure the following communication capabilities:

1. telephone;
2. telefax;
3. telemetering and remote alarm indication;
4. remote control;
5. remote reading of data from commercial metering devices.

Art. 41. The contract concluded pursuant to Art. 62 the transmission service provider and the Users shall agree upon assignment of responsibilities in the point of connection and shall specify:

1. ownership, control, maintenance;
2. operating worksheets;
3. list of facilities;
4. list of metering and telecommunication devices;
5. access to the site;
6. relay protection inspection checks;
7. repair works;
8. safety coordination.

Section IV

Technical Requirements to Generator Connection

Art. 42. (1) The synchronous and induction electric generators shall be fitted for continuous operation in any possible operating and weather conditions on the site of their installation.

(2) The electric generators shall be designed and installed in such a manner as to withstand, without failures, unexpected three-phase short circuits at the generator terminals.

(3) The rated active and reactive power of electric generators shall be retained in the event of voltage deviation in the power plant connection point ± 5% and frequency deviation ± 2,5 %.

Art. 43. (1) The PS operator defines requirements towards the generators who influence the operation reliability of the power system and are needed for implementation of the defense plan and the restoration plan.

(2) Electricity generators operating thermal power plants (TPP) shall accept and perform:

1. Automatic generation islanding (GI);
2. Participation in restoration paths after a system accident;
3. Provision of communications.

(3) Electricity generators operating storage hydropower stations shall accept and perform:

1. “Black start” capability;
2. Operation in an island mode and resynchronization with the power system;
3. Participation in restoration paths after a system accident;
4. Provision of communications.

Art. 44. (1) All synchronous generators shall be fitted with an excitation system assuring continuous operation at rated excitation of the synchronous generator under limit operating mode for the particular power plant.

(2) The excitation system shall provide capability for increasing (boosting) of the excitation current and voltage of the synchronous generator as follows:

1. for hydraulic-turbine generators 25 MVA or less: least common multiplicity 1,5/minimum time 10 s;
2. for hydraulic-turbine generators more than 25 MVA – least common multiplicity 1,8/minimum time 20 s;
3. for turbo-generators 25 MVA or less: least common multiplicity 1,8/minimum time 10 s;
4. for turbo-generators more than 25 MVA – least common multiplicity 2,0/minimum time 30 s;

(3) The boost parameters shall be achieved with voltage at the generator terminals in the range 80% to 120% of the rating and frequency in the 47,0 Hz – 53,0 Hz range.

(4) The variation rate of the synchronous generator excitation voltage shall not be less than 2 p.u./s taking as basis the excitation voltage at rated synchronous generator load.

Art. 45. (1) All synchronous generators with electrical power more than 5 MVA shall be equipped with an automatic excitation control.

(2) The automatic excitation regulators shall assure voltage sustaining at the generator terminals within the following precision limits:

1. for generators up to 25 MVA – minimum ± 1%;

2. for generators over 25 MVA – minimum ± 0,5%;

(3) The automatic excitation regulators shall assure the capability for compensation of a voltage drop in the main transformer as well as stable reactive power distribution among the synchronous generators connected to common buses.

(4) The automatic excitation regulators shall be able to limit the minimal excitation, the maximum rotor current, maximum reactive/idle stator current of the synchronous generator.

(5) The automatic excitation regulators of synchronous generators with electrical power more than 25 MVA shall have a circuit for stabilization of its operation during synchronous fluctuations (system stabilizer) with possibility for adjustment of the stabilizer parameters.

(6) The systems for automatic excitation regulation of generators designed for participation in PS restoration after major accidents (water and gas turbines), shall be able to regulate the voltage upon initial excitation of the synchronous generator in the absence of an external source of alternating voltage for house supply ("black" start).

(7) The automatic excitation regulators of synchronous generators with more than 25 MVA power shall provide possibility for control at a higher hierarchical level - through connection to an excitation ganged control system.

Art. 46. (1) All synchronous units with electrical power more than 5 MVA shall be equipped with systems for automatic adjustment of the turbine rotation speed and active power.

(2) The systems for automatic regulation of turbine active power shall provide a possibility for adjustment of minimum and maximum active power limits of the synchronous generator during operation in parallel with the power system, depending on the turbine features, in the 0% - 110% range.

(3) The systems for automatic regulation of turbine active power shall provide a possibility for maintaining the active power assigned to the generator within the following precision limits:

1. for units not exceeding 25 MW – minimum ± 2%;

2. for units over 25 MW – minimum ± 1%;

(4) The systems for automatic regulation of turbine rotation speed shall provide a possibility for equalization of the synchronous unit frequency to that of the power system before putting the generator into parallel operation with precision ± 0,1%.

(5) The systems for automatic regulation of the power and rotation speed of turbines of capacity exceeding 25 MW shall be able to switch over from power regulation mode to speed regulation mode upon disconnection of the generator from the network without triggering the overspeed protection.

(6) The systems for automatic turbine speed regulation shall provide a possibility for speed limitation and overspeed protection of the synchronous generating unit with capability for adjustment within the range:

1. for steam turbines – from 104 % to 112 % of their rated value;

2. for water and gas turbines - from 104 % to 130 % of their rated value.

(7) The systems for automatic turbine speed regulation of generating units designed for participation in primary frequency control in the PS shall:

1. have a permanent, inherent to the control system, dead band not exceeding 20 mHz;

2. be able to adjust the insensitivity band up to 500 mHz for the range from 49,0 Hz to 50,5 Hz;

3. perform static characteristic regulation with possibility for droop adjustment within the 0 – 10% range.

(8) The systems for automatic turbine active power regulation of units designed for participation in the secondary load and frequency control of the power system shall provide a possibility for higher-hierarchical level variation of the assigned active power.

(9) The systems for automatic turbine speed regulation of units designed for participation in PS restoration after accidents (water and gas turbines) shall provide a possibility for independent operation mode of the synchronous generator with isolated load (island mode) and for resynchronization where control is effected after a modified static or astatic characteristic. Transition from the assigned static characteristic to another static or astatic characteristic shall be done:

1. by criteria built into the regulator (upper or lower frequency limit, frequency or load variation rate);

2. by the power plant operator using a control key;

3. remotely, by means of a telesignal from the dispatching center or depending on the condition of the switching equipment.

(10) The systems for automatic turbine speed regulation of units designed for participation in PS restoration after major accidents (water and gas turbines) shall provide a possibility for acceleration and loading in the absence of an external alternating voltage source for house supply (“black” start).

Art. 47. (1) The setting range of the automatic excitation control systems, system stabilizers and active power control of synchronous generating units is determined at the time of selection of the control systems and drawing up a detailed design coordinated with the PS operator.

(2) Before putting the systems into trial or commercial operation, the operating mode and priority settings, the intensification factors, time constants, limiters and other parameters shall be specified on the basis of updated calculations and reviewed jointly with the PS operator.

Art. 48. The transmission service provider and the Users shall use an unified system approved by the transmission service provider for designation of all facilities in the connection points to guarantee reliable and safe operation of the power system.

Art. 49. (1) The volume and organization of the relay protections of generators, step-up transformers, buses and power lines – property of the generator shall, as a minimum, meet the requirements of the Regulation on Design of Electrical switchgears and Power Lines.

(2) The impedance, current and operation time settings of short-circuit relay protections in the power system (external to the generators and step-up transformers in the power plant) shall be coordinated with the PS operator.

(3) Relay protections on the power plant tie lines to the power system shall be in conformity with the prevailing standards, regulations and procedures.

(4) The electrical facilities shall be protected by means of main and standby relay protections acting independently.

(5) In 220 kV or higher-voltage power lines and system-interconnection lines, the relay protections shall be organized on the "full local backup" principle in compliance with the Regulation on Design of Electrical switchgears and Power Lines. One of the protections shall be of a distance type.

(6) For connection to networks with directly earthed star point, the power lines shall be additionally equipped with directional three-stage overcurrent protection with current-independent time delay. Individual or, as required, ganged earth-fault protection is set up on the high side of step-up transformers.

(7) In any case, with main operation of the relay protections (with first zone, first stage, differential protection) the power lines shall be disconnected for a time not exceeding 150 ms, including the circuit-breaker time both on the power plant side and on the PS side.

(8) In the case of connection through a transformer and a power line, a combination of longitudinal differential and distance relay protection is recommended. The first is a main protection and protects the transformer and the power lines, and the second is installed on the high side of the step-up transformer, backs up the longitudinal differential protection in the event of short circuits along the power line and serves as distance standby in the event of short circuits on other connections outgoing from the transmission service provider's switchgear.

(9) In the case of connection through power lines, a combination of two distance protections or a combination of distance and longitudinal differential relay protection of the connecting lines is recommended.

(10) The combination, type and functions of relay protections are subject to agreement between the power plant and the PS operator.

(11) The responsibility for normal functioning of the relay protections of the power lines connecting a power plant to the power system shall be borne:

1. On the part of the power plant – by its owner;

2. On the part of the PS – by the transmission service provider.

(12) The reliability of relay protection operation shall not be less than 99% determined as relationship between successful trips to the total number of faults.

Art. 50. (1) The availability and type of automatic reclosing (ARC) – single-phase, three-phase, synchronism control or absence of tension for power lines connecting the power plant to the power system, is subject to agreement between the power plant and the PS operator on the basis of transient stability calculations.

(2) The specific settings for ARC shall be agreed upon with the PS operator.

Art. 51. (1) In order to prevent spreading of an accident in the event of failure of a breaker participating in the connection between the power plant and the power system, an

BFP shall be used for automatic opening of all breakers adjacent to the breaker that has failed to open.

(2) The need for an BFP is agreed upon with the PS operator on the basis of stability calculations.

(3) The device is built on the “Breaker BFP” principle.

(4) The installation, commissioning and maintenance of a BFP is an obligation of the owner of the facility where it is implemented.

(5) The particular settings and effect of a BFP are determined jointly with the PS operator.

Art. 52. (1) The signal transmission devices for relay protection acceleration and for remote breaker opening are subject to design and coordination with the PS operator.

(2) Power lines connecting the power plant with the power system at 110 kV or higher voltage level, shall be mandatorily equipped with signal transmission devices for acceleration (joint operation) of the relay protections at both ends of the connecting line.

(3) Automatic remote opening of the breaker in adjacent switchgear upon actuation of an BFP shall be agreed upon as required.

(4) The supply and installation of signal transmission equipment is an obligation of the owner of the switchgear where it is to be installed.

(5) The signal transmission time shall not exceed 20 ms.

Art. 53. (1) All electrical connections to switchgears of 110 kV and higher voltage shall be equipped with precise synchronization systems.

(2) Synchronous electricity generators and units with capacity more than 12 MW shall be equipped with precise automatic synchronization systems.

(3) When the synchronous electricity generating units have less than 12 MW capacity and have no precise automatic synchronization system, they shall at least be equipped with manual precise synchronization devices with interlocks against asynchronous switching.

(4) Switching of synchronous electricity generating units with unit capacity less than 5 MW by the auto-synchronization method is allowed for units with capacity 5 MW or less.

(5) Switching of synchronous electricity generating units with unit capacity more than 5 MW by the auto-synchronization method is allowed after coordination of each particular case with the PS operator.

Art. 54. (1) Electricity generation units at thermal power plants with rated power more than 25 MVA shall be equipped with an AFS system, inclusive of the auxiliary supply system in the event of emergency frequency drop in the power grid.

(2) The AFS system shall be capable of frequency adjustment in the 46 Hz – 50 Hz range and time adjustment in the 0 – 3 seconds range.

Art. 55. (1) Synchronous generating units for which pole slip (with or without excitation) is allowed according to the manufacturer’s information shall be checked for stability in the point of their connection to the power grid.

(2) In cases where pole slip is not permissible from the stability point of view, the generators shall be equipped with pole slip protection that disconnects the generator from the network.

Art. 56. (1) The relay protection settings at power plants are defined and proposed in the design. Before the start of operation, they shall be particularized and coordinated with the PS operator on the basis of updated calculations.

(2) The relay protection settings at the connection points between power plants and the power system shall be defined by the PS operator.

(3) The setting of relay protection and automatic devices installed on the premises of a power plant is mandatory to and shall be performed by the power plant owner.

Art. 57. The following communication means shall be provided for the purpose of PS dispatching:

1. telephone;
2. telefax;
3. telemetering and remote alarm indication;
4. remote control;
5. remote regulation;
6. remote reading of indications from commercial metering devices.

Art. 58. (1) The transmission service provider and the generators shall agree on the assignment of responsibilities in the connection point and shall particularize the following points:

1. Property, dispatching, maintenance;
2. Operational schemes;
3. List of facilities;
4. List of metering and telecommunication devices;
5. Access to the site;
6. Inspection of relay protections;
7. Repair works;
8. Safety coordination.

Section V

Technical Requirements towards Connection of Distribution Companies' Facilities to the Transmission system

Art. 59. Connection of distribution companies' facilities to the transmission system shall be effected after the procedure of Part Four "Connection of Distribution Companies' Facilities to the Transmission system" of the Regulation on Connection of Electricity Generators and Consumers to the Transmission and Distribution Network".

Art. 60. (1) The requirements of Sections I, II and III of Chapter Three of this Code shall apply to every point of connection of a distribution company's facility to the transmission system.

(2) In the event of existing generating capacities connected to the distribution network subject to connection to the transmission system, the requirements of Section IV of Chapter Three shall apply in addition.

(3) The distribution company shall submit written technical data of the distribution network (including the generating capacities connected to it) to the transmission service provider for setting the conditions of connection to the transmission system.

Art. 61. Connection of generating capacities to the distribution network shall be performed in conformity with the requirements of Section IV of Chapter Three of these Rules.

Chapter Four
USE OF THE TRANSMISSION SYSTEM

Art. 62. Transmission system Users shall conclude contracts with the transmission service provider for electric power transmission and/or use of the transmission system in conformity with the provisions of these Rules.

Art. 63. (1) The transmission system Users who are market participants within the meaning of Art. 100 of the Law on Energy shall be balanced by the PS operator by the procedure and on conditions set out in the Electricity Trading Rules [Market Rules] pursuant to Art. 91 (2) of the Law on Energy.

(2) By means of joint use of the primary, secondary and tertiary regulation reserve the PS operator achieves overall balance between electricity generation and consumption in the control block.

(3) The power used for balancing of each User under Art. 100 of the Law on Energy shall be determined after the settlement period concerned in the order and manner defined in the Electricity Trading Rules.

Art. 64. (1) All points of electric power interchange between the transmission system and transmission system Users shall be equipped with commercial electricity metering devices in conformity with the Rules as per Art. 83 para. 1, item 6 of the Law on Energy.

(2) For purposes of participation in the electricity market the Users may associate by forming balancing groups.

Art. 65. (1) Electric power interchange between a balancing group and other transmission system Users and/or other balancing groups shall be effected after interchange schedules incorporating all supply schedules of all Users whose facilities are included by such balancing group.

(2) The balancing group's interchange schedules shall be drawn up by a person in charge of the balance within the balancing group on the grounds of a concluded contract and registered for participation in the balancing power market pursuant to the Electricity Trading Rules.

(3) The person under para. 2 shall notify the PS operator of:

1. the User's facilities included in the balancing group;
2. points of interchange and the commercial metering devices installed in such points;
3. schedules of interchange between the balancing group and other Users and/or balancing groups;
4. any changes in the components and points of power interchange within time limits and in the manner indicated in the Electricity Trading Rules.

(4) The person under para. 2 shall be responsible for the group's balance with respect to other balancing groups and/or Users and shall be a party to balancing power transactions for the group's interchange schedules.

Art. 66. (1) The amount of electricity delivered to each balancing group in the points of interchange shall be equal to the sum of the amounts of electricity under the electricity purchase schedules of other balancing groups and/or Users of the transmission system.

Art. 67. (1) Electricity transmission through the transmission system in the course of power supply by generators to their enterprises and facilities shall be effected on the conditions of Art. 32 and Art. 104 of the Electricity Trading Rules.

(2) When the facilities under para. 1 belong to different balancing groups the amount of electricity transmitted from the generation facilities to the consumption facilities shall be added to the amounts in the interchange schedules of the balancing groups drawn up by the persons in charge of the balance.

(3) When the facilities under para. 1 belong to one balancing group while the transmission of electricity takes place through components of the transmission and/or distribution network, the person in charge of the balance shall draw up and submit to the operator a separate schedule for that electricity only.

Chapter Five

EPS OPERATION PLANNING

Section 1

Demand Forecasts

Art. 68. The transmission service provider shall produce demand forecasts for the purposes of:

1. investment planning for a period longer than 5 years;
2. annual planning – by months for the following calendar year;
3. weekly planning – one week in advance;
4. daily planning – 24 hours in advance;
5. planning for the current day and post-operation control.

Art. 69. (1) The distribution companies shall present to the transmission service provider data reports for every month of the preceding calendar year for the purposes of investment and annual planning in or before the end of March of the current year covering:

1. electricity purchased and daily load curves of generators with installed capacity 200 kW or more connected to the distribution network as follows:

(a) for the days of minimum and maximum load on the distribution network;

(b) for the days of minimum and maximum load on the transmission system;

(2) The monthly amounts of electricity delivered to the distribution network shall be broken down as follows:

1. industrial consumers;
2. agricultural consumers;

3. utilities;

4. transport;

5. street lighting;

6. households;

7. electricity distribution losses.

Art. 70. (1) The distribution companies shall present to the transmission service provider, for each point of connection to the transmission system, forecast data for each of the next five calendar years for the purposes of investment planning in or before the end of March of the current year in conformity with Art. 90 item 3 of the Law on Energy as follows:

1. annual amounts of electricity;

2. maximum and minimum capacities.

(2) In their forecasts, the distribution companies shall take into account the electricity output envisaged by the generators connected to the respective distribution networks as well as the losses related to electricity distribution.

Art. 71. The customers connected to the transmission system shall submit to the transmission service provider reports on the electricity produced by means of their own sources for each month of the preceding calendar year for the purpose of investment and annual planning, before the end of March of the current year, as follows:

1. Electricity quantities;

2. Load curves on days of minimum and maximum load;

3. load curves on days of minimum and maximum load on the transmission system.

Art. 72. (1) The customers connected to the transmission system shall submit to the transmission service provider, for each point of connection to the transmission system, forecast data for each of the next five calendar years for the purpose of investment and annual planning, before the end of March of the current year, as follows:

1. Annual quantities of electricity;

2. minimum and maximum capacities in the respective years;

(2) In their forecasts, the customers connected to the transmission system shall take into account the envisaged electricity output from their own sources.

Art. 73. (1) The distribution companies shall submit to the transmission service provider, for each point of connection to the transmission system, monthly forecasts for the next calendar year for the purpose of investment and annual planning, before the end of March of the current year, as follows:

1. quantities of electricity;

2. minimum and maximum levels of active and reactive power;

(2) Besides the data under para. 1, the following monthly forecast data shall be submitted:

1. own electricity sources as follows:

a) electricity quantities;

b) maximum and minimum levels of active and reactive power of the generating sources;

2. Electricity purchased/sold by/to neighboring distribution companies as follows:

a) electricity quantities;

b) maximum and minimum levels of active and reactive power;

Art. 74. (1) The customers connected to the transmission system shall submit to the transmission service provider, for each point of connection to the transmission system, monthly forecast data for the next calendar years for the purposes of annual planning, before the end of March of the current year, as follows:

1. quantities of electricity;

2. minimum and maximum levels of active and reactive power.

(2) In addition to the data under para. 1, monthly forecast data on the own electricity sources shall be submitted as follows:

1. electricity quantities;

2. maximum and minimum levels of active and reactive power of the generating sources.

Art. 75. In the event of adjustment of the monthly forecast data by more than 5%, the respective User shall send the new data to the transmission service provider within 30 days after the change.

Art. 76. (1) The transmission service provider shall notify the distribution companies and the customers connected to the transmission system about the maximum-load day and minimum-load day of the transmission system for the respective months of the report year, before the end of January of the next year.

(2) The distribution companies and customers connected to the transmission system shall notify the transmission service provider about the maximum-load and minimum-load days of their networks for the respective months of the report year before the end of January of the next year.

Art. 77. (1) The transmission service provider shall receive the following information for the purpose of weekly and daily planning:

1. The market participants in transactions at freely negotiated prices shall present information about bilateral electricity supply contracts, physical nomination, as well as balancing proposals and notifications of balancing of the balancing power market in conformity with the Electricity Trade Rules;

2. The public provider shall present all schedules agreed upon with electricity importers and/or exporters pursuant to Art. 93, para. 2 of the Law on Energy within the next week (from 00.00 hrs. on Monday till 24.00 hrs. on Sunday).

(2) The data under para. 1, item 2 shall be submitted not later than at 09.00 hrs. on Friday of the preceding week.

Art. 78. The transmission service provider shall develop the respective types of demand forecasts on the basis of the information provided, additionally taking into account the following factors:

1. Load curves for past periods that are of significance for the daily planning;

2. Weather forecasts as well as actual weather reports;

3. Load curves on special days – national, religious and other holidays;

4. Load curves of forced pumping mode at the pumped-storage hydro-power station;

5. Statistical and prognostic data of the economic development of Bulgaria.

Art. 79. (1) The transmission service provider shall develop forecasts of electricity losses in the transmission system taking into account:

1. losses in power lines and transformers;
2. losses in compensating devices;
3. consumption of MV electric power at substations of the transmission system.

(2) Calculations in relation to the forecasts under para. 1 shall be made on monthly basis and shall incorporate capacity and power losses.

(3) Losses shall be calculated on the basis of forecast data about generation, demand and transmission system topology.

Section II

Cold Reserve and Annual Maintenance Planning. Planning of Overall Availability and Forecasts of Electricity Surplus / Shortage

Art. 80. This Code enables the PS operator to plan the cold reserve under Art. 105 of the Law on Energy, to coordinate availability planning and generating unit maintenance schedules in order to meet demand requirements in accordance with the level of reliability determined with reference to Art. 4, para. 2, item 4 of the Law on Energy.

Art. 81. (1) The cold reserve planning procedure is the following:

1. Before the 31st June of the current year the Minister of Energy and Energy Resources shall issue an order defining the mandatory indicators, pursuant to Art. 4, para. 2, item 4 of the Law on Energy, for the next calendar year, on the basis of the principle of equal costs of maintaining the required reserve and of covering the losses from energy unsurved during the considered period. In order to determine the costs, the following are assumed:

a) forecast price for availability of the cold reserve;

b) cost of the specific loss from undelivered electric power 8.00 BGN/kWh – according to data from EU member countries due to absence of methodology for the country.

2. Modeling of generating capacity availability:

a) the model is based on building the probabilistic distribution function of the total available capacity of the power system. For that purpose, the method of equivalent normal distribution is applied on the basis of data about available capacities and stationary availability factors of the individual units.

b) the units in condensing power plants are represented individually through their actual available capacities and actual availability factors for the preceding year. The district heating companies are represented jointly as one single equivalent plant with available capacity corresponding to the mean statistic capacity implemented by such plants over the preceding year. The power plants of industrial works are represented in the same manner. Hydropower stations are equivalented in terms of mean operating capacity on the basis of possible annual quantity of electric power that can be generated in the conditions of a normally humid year. Under that assumption, the hydro-power stations are presented as an equivalent power plant consisting of ten 40 MW units and total capacity 400 MW;

c) definition of the probabilistic distribution function of total available capacity:

$F_g(g) = \dots \int_{-\infty}^{g} f_g(g)dg$, where:

$f_g(g) = \dots \dfrac{e^{-\left(g-\overline{g}\right)2\delta_g^2}}{\delta_g(2\pi)^{0.5}}$ is probabilistic distribution density;

$g = \dots \sum_{i=1}^{n_g} g_i p_i$ .. – mathematical expectation of the total available capacity;

δ_g^2 – dispersion of the total available capacity of generation:

$\delta_g^2 = \dots \sum_{i=1}^{n_g} g_i^2 p_i (1 - p_i)$, where:

g_i is available capacity of the i-th unit (actual or equivalent);

p_i - stationary availability factor the i-th unit;

n_g - total number of units considered (actual or equivalent).

3. Load modeling:

The model of PS load is based on a normal probabilistic distribution of mean hour loads:

$F_w(w) = \dots \int_{-\infty}^{w} f_w(w)dw$, where:

$f_w(w) = \dfrac{e^{-\left(w-\overline{w}\right)2\delta_w^2}}{\delta_w(2\pi)^{0.5}}$ is probabilistic distribution density;

w – mathematical expectation of the forecast load;

δ_w^2 - load dispersion determined on the basis of statistical data.

Depending on the objectives of modeling the PS load may represent only the load in the country or the total load of the country and the balance of contracted import and/or export of electricity.

4. Power balance modeling:

The power balance model is based on equivalent normal distribution of the resultant quantity obtained as available capacity and load difference. According to the law of summing/extraction of normally distributed random values the balance will have the following parameters:

z = g – w – mathematical expectation of the balance;

$\delta_z^2 = \delta_g^2 + \delta_w^2$ - balance dispersion.

The distribution function will be:

$F_z(z) = \ldots \int_{-\infty}^{z} f_z(z)dz$, where:

$f_z(z) = \ldots \frac{e^{-\left(z-\bar{z}\right)2\delta_z^2}}{\delta_z(2\pi)^{0.5}}$ - is probabilistic distribution density.

5. Integral indicators of PS adequacy:

a) conditions of calculation:

- minimum conditions corresponding to the minimum load on the power system. At P_{min}, a mean-square load deviation δ_w is determined;

- average conditions corresponding to the mean load on the power system. At P_{cp}, a mean-square load deviation δ_w is determined.

- maximum conditions corresponding to the maximum load of the power system. At P_{max} a mean square deviation of the load δ_w is defined.

- General conditions:

- Length of the considered period in hours: *T* = 8760 h;
- The length of the respective periods is determined on the basis of forecasts for the report year;

b) The full probability of power shortage is:

$I_{def} = F_z(0)$;

c) the power adequacy coefficient is:

$Kr = 1 - I_{def}$.

The coefficient Kr is calculated as average value of that determined on the above-shown calculation conditions. An integration method is applied with adding or subtracting of generation units with their actual availability factors until a mean coefficient corresponding to that determined under Art. 83 item 1, is obtained.

d) The quantity of unsupplied power is determined by means of:

$E_{unsv} = T \int_{-\infty}^{0} zf_z(z)dz$, where:

T is the length of the period considered, h;

e) the cold reserve values are calculated as difference between the availability corresponding to the average coefficient Kr, and the availability corresponding to the expected forecast mean load per hour.

Art. 82. (1) The advance planning of availability and determining the forecast surplus/shortage of electricity, as well as planning of annual maintenance of generating units shall follow the procedure below:

1. Before the 31st August of the current year, on the basis of the annual demand forecast and cold reserve plan, the PS operator shall send the electricity generators forecast data about the availability and monthly output during the next calendar year;

2. Before the 15th September of the current year, all generators connected to the transmission system shall send to the PS operator substantiated initial proposals for maintenance programs for the next year that shall include:

a) dispatch name of the generating unit;

b) declared capacity of the generating unit;

c) length of the intended maintenance;

d) preferable time period of maintenance;

3. The PS operator shall draw up a tentative availability program and a tentative maintenance program on the basis of the substantiated proposals taking into account the requirements of:

a) forecast demand;

b) long-term electricity purchase/sale contracts;

c) the needed cold reserve;

d) forecasts of hydrological reliability, available and expected water discharge to the water basins;

e) technical restrictions on the cascade operation of hydro-power stations;

f) compliance with the requirements for complex utilization of water.

4. Before the 30th September of the current calendar year, the PS operator shall present the tentative availability program and the tentative maintenance program to the generators concerned;

5. The PS operator and the parties concerned shall hold consultations in order to reach an agreement in the cases where the initial proposal cannot be accepted;

6. When no agreement can be reached, the PS operator has the right to define the maintenance periods proceeding from the requirements under item 3.

7. The PS operator shall draw up the general availability program and the final maintenance program before the 31st October of the current year and send them to the electricity generators.

8. The PS operator shall submit forecast data about electricity surplus/shortage to the public provider.

Art. 83. The planning procedure of short-term repairs of generating units is as follows:

1. short-term repairs of generating units shall be planned as a percentage of availability during the year;

2. the time period of their performance is not regulated in the annual plan; it is determined by filing a written application by the generators to the PS operator in conformity with the Regulation on Conditions and Procedure Governing the Work of Transmission and Distribution Network Operators as well as Shift Operators of Electric Power Facilities and Customers' Electrical Switchgears and the respective permission issued by the PS operator.

Art. 84. The following procedure shall be observed in cases of forced outages of generating units:

1. In the cases where the generating unit forcedly drops out of operation, the respective generator shall promptly inform the PS operator of such event;

2. the party concerned shall immediately present information about the probable length of the forced outage and any other relevant information to the PS operator.

Art. 85. (1) The PS operator shall issue permissions for scheduled maintenance in conformity with the Regulation on Conditions and Procedure Governing the Work of Transmission and Distribution Network Operators as well as Shift Operators of Electric Power Facilities and Customers' Electrical switchgears.

(2) On the starting date of the scheduled maintenance, the PS operator shall assess the operation mode on that particular date and may postpone the scheduled maintenance in cases where the requirements for reliability of electricity supply have not been met.

(3) The PS operator shall agree with the generator concerned upon a new time limit for scheduled maintenance, but in any case such postponement shall not exceed 7 calendar days, unless the parties agree otherwise.

Section III

Allocation and Drawing up of Annual Availability Schedules. Electricity Generation Schedules

Art. 86. This Code defines the procedures by which the PS operator shall draw up the final availability schedules and allocate the output of the generating units so as to assure reliability and quality of electricity supply.

Art. 87. For the purposes of annual and monthly planning, before the 15th of November of the current year:

1. Electricity generators shall present the following information to the PS operator:

6. monthly schedules of electricity supply for the next calendar year under bilateral contracts concluded as of that date pursuant to Art. 100 of the Law on Energy and the availability envisaged for that purpose.

7. the PS operator shall notify the public provider of the remaining availability determined in conformity with Art. 82, item 7;

8. the public provider shall negotiate in advance with the generators the amounts of availability and electric power required to meet demand in the country at regulated prices and least total costs of availability and electric power and shall duly inform the PS operator;

9. within the limits of the remaining availability, the PS operator shall negotiate with the generators availability needed to support the planned cold reserve at the least cost and shall inform the public provider of the resultant surplus/ shortage.

10. In the event of surplus under item 1.d. the public provider shall conclude contracts with the generators for the availability under item 1.c. and for the surplus under item 1.d.

11. In the event of shortage under item 1.d., the public provider shall reduce the availability agreed upon in advance as per item 1.c. so as to secure the availability corresponding to the planned cold reserve;

12. The public provider shall plan conclusion of contracts for electricity import matching the shortage under item 1.d.;

2. Before the 30th of November of the current calendar year, the PS operator shall inform the parties concerned about the final monthly allocation of availability, including that for cold reserve in accordance with Art. 82 and about the monthly amounts for electricity generation.

Art. 88. (1) For the purpose of monthly planning, the market participants shall submit information about the weekly delivery schedules pursuant to the transactions at freely negotiated prices on the terms and conditions of the Electricity Trading Rules.

(2) At or before 09:00 hrs. on Friday of the current week, the PS operator shall receive information for the next week as follows:

4. from electricity generators operating condensing power plants – changes in the parameters and technical characteristics of generating units and amendment of the terms and conditions of delivery of ancillary services, as well as expected restrictions on generation;

5. from electricity generators operating co-generation power plants – electricity generation schedules determined by the generation of heat energy;

6. from the public provider:

a. electricity import/export schedules;

b. schedules of mandatory buying out of electricity by the “take or pay” scheme.

(3) Before 11:00 hrs on Friday of the current week, the PS operator shall coordinate with the operators concerned in the synchronous zone and with the разчетния координационен център /settlement coordination center/ the interchange schedules for the next week.

(4) Before 16:00 hrs on Friday of the current week, the PS operator shall draw up a tentative schedule of operation of the generators’ generating units on the basis of the information under paragraphs 1, 2 and 3 and demand forecasts.

(5) Before 17:00 hrs on Friday the PS operator shall inform the electricity generators of the changes, if any, in the make-up of generating units for Saturday, Sunday and Monday.

(6) The weekly delivery schedules for market participants under para.1 shall encompass the period from 00:00 hrs. on Saturday of the current week till 24:00 hrs on Friday of the next week.

Art. 89. (1) For daily planning purposes, the market participants shall present, and the PS operator shall keep register proposals for balancing and notifications of balancing on the terms and conditions of the Electricity Trading Rules.

(2) Every day at 10:00 and 15:00 the PS operator shall update the load forecasts for the current day and for the next six days and shall inform the parties concerned about any changes in the make-up of generating units, if any such changes are intended.

(3) The procedures under paragraphs 1 and 2 shall be performed every week day, and on Friday – for the week-end days and Monday.

Art. 90. (1) Upon the set-in of circumstances that disrupt the safety or quality and reliability of operation, the PS operator has the right:

1. to interrupt the operation of electricity market pursuant to the Electricity Trading Rules;

2. to cancel the planned schedules of generators;

3. to issue operative instructions for new operation schedules of all generators without exceptions, within their technical possibilities.

Art. 91. The minimum scope of generating unit technical parameters for planning purposes is as below:

1. for thermal power units:

a) synchronization time starting from different turbine modes;

b) time of reaching the technical minimum;

c) technical minimum level;

d) load variation rate between technical minimum and rated capacity;

e) tripping time;

f) primary control reserve;

g) secondary control reserve;

h) power curve of the synchronous generator;

i) permissible number of start/shutdown cycles within a definite time period;

j) rated capacity;

k) other parameters agreed between the parties concerned;

2. For hydro-power sets:

a) startup time;

b) permitted operation range;

c) primary control reserve;

d) secondary control reserve;

e) capability for “black start” and “island” mode operation

f) power curve of the synchronous generator;

g) load variation rate;

h) cascaded operation restrictions;

i) limitations imposed by the primary energy source;

j) rated capacity;

k) other parameters agreed between the parties concerned.

Section IV

Ancillary Service Planning

Art. 92. This Section defines:

1. The types of ancillary services;
2. Quality criteria for the services provided;
3. Criteria applied by the PS operator in their planning.

Art. 93. (1) Ancillary services shall be provided by the transmission system Users upon instructions issued by the PS operator during on-line control of the power system and shall be regulated by contracts.

(2) The PS operator shall perform its main function of reliable, high-quality and efficient PS dispatching through provision of system services using the ancillary services provided.

Art. 94. The ancillary services include:

1. participation of generating units in the primary frequency control;

2. participation of generating units in the secondary load and frequency control;

3. participation in tertiary frequency control;

4. participation in voltage regulation in the point of connection to the transmission system or regulation of the reactive power flow from/to the transmission system.

Art. 95. In pursuance of its obligations related to frequency control and active power and voltage control, the PS operator shall plan the delivery of ancillary services as listed below:

1. participation in primary frequency control;

2. participation in secondary load and frequency control;

3. participation in tertiary frequency control;

4. participation of Users in voltage regulation in the transmission system.

Art. 96. The conditions on which ancillary services are provided to the PS operator under contracts with transmission system Users shall offer possibilities for:

1. qualitative and quantitative evaluation of services through measurement of certain parameters in a manner agreed upon between the parties;

2. inspections by the PS operator at any time;

3. proving the capability for provision of the services by means of regular tests.

Art. 97. (1) Primary frequency control is effected by activating the primary control reserve provided by electricity generators' generating units upon a change of frequency in the power system.

(2) The primary control reserve P_p is the positive portion of the primary control range from the operational point before the disturbance to the maximum capacity for primary control. The concept of primary control reserve is applicable to generating units as well as reference controlled units (as is the type of the Bulgarian power system). The required primary control reserve is allocated among the individual control blocks from the accounting centre of the synchronous zone.

(3) Provision of the primary control reserve is defined using the following indicators:

1. droop of the turbine governors calculated by the equation:

$$\sigma = \frac{\Delta f * Pn}{fn * \Delta P} * 100,$$ where:

ΔP is the change of the capacity of the unit, MW

P_n – rated capacity of the unit, MW;

Δf – frequency deviation, Hz;

f_n – rated frequency of the power system, Hz.

The droop of turbine governors shall be an adjustable value within the range 2% to 10%. Its exact value shall be set by the PS operator;

2. A dead band in which the turbine governor does not operate upon a frequency change. It should be an adjustable value within the range ± 0,5 Hz of the rated frequency. The dead band setting should be equal to zero unless the PS operator has set another value;

3. an insensitivity band in which the turbine governor does not operate upon a frequency change due to defects in its design. It is determined by the design of the turbine governor and shall not exceed the range ± 10 mHz;

4. size of the primary control reserve which shall not be less than 5% of the rated capacity of the unit. Its exact value is set by the PS operator depending on the PS requirements and on the technical characteristics of the generating unit;

5. full activation time of the primary control reserve that shall not be more than 30 s from the moment of frequency interference;

6. maintenance of the primary control reserve – the generating unit should be able to maintain the activated primary control reserve throughout the PS frequency deviation from the setting.

(4) The PS operator shall plan the primary control reserve on the basis of the following criteria:

1. during operation of the Bulgarian PS in parallel to other power systems the total amount of the primary control reserve in the PS of Bulgaria shall be in conformity with that defined in the effective parallel operation agreements for the respective year;

2. during independent operation of the PS of Bulgaria the primary control reserve shall not be smaller than the possible active power shortage that may arise in the PS of Bulgaria in the event of emergency trip of a generating capacity;

3. the total primary control reserve shall be distributed as uniformly as possible among the power units that can provide it, taking into account their cost indicators (merit order dispatching) and technical characteristics.

Art. 98. (1) Secondary load and frequency control is carried out through automatic variation of the active power of generators participating in the control within the secondary control range provided by the generating units to electricity generators in conformity with the assignment sent by the central regulator of frequency and interchange power.

(2) The positive part of the secondary control range, from the operational point to the maximum value of the secondary control range, constitutes a reserve for upward secondary control. The part of the secondary control range that has already been utilized to the operational point, is called secondary control capacity. The negative part of the secondary control range, from the operational point to the minimum value of the secondary control range, constitutes a reserve for downward secondary control.

(3) Provision of a secondary control reserve is defined by means of the following indicators:

1. Stable operation of the unit in the event of variation of the active power assignment;

2. Variation rate of the active power of an unit:

a) for hydro-power stations – at least 1,5% of the rated power per second;

b) for thermal power plants – at least 1,5% of the rated power per minute;

3. precision of performance of the active power assignment – more than 2% for hydro-power units and 5% for thermal-power units of the rated power.

(4) The secondary control reserve is planned on the basis of the criteria listed below:

1. Size of the reserve – in conformity with the expression:

$R = \sqrt{aL_{\max} + b^2} - b$, where:

L_{max} is the maximum load in the control area for the planning period, MW;

a = 10 MW;

b = 150 MW;

2. The total secondary control reserve shall be distributed as uniformly as possible among the power units that can provide it, taking into account their cost indicators (merit order dispatching) and technical characteristics.

Art. 99. (1) Tertiary power control is implemented through activation of the tertiary control reserve provided by the generating units to electricity generators, consumers participating in the balancing power market, or by external partners from the synchronous zone.

(2) The tertiary control reserve is the load that can be automatically or manually transferred within the tertiary control framework in order to provide an adequate secondary control reserve. It shall be activated in such a manner that it should contribute on time to restoration of the secondary control reserve.

(3) The PS operator shall plan the tertiary control reserve on the basis of the following criteria:

1. activation time of the full value – maximum 15 minutes;

2. time of maintenance of the reserve output – as long as required for restoration of the secondary control reserve.

Art. 100. (1) Voltage control in the transmission system is carried our by the PS operator by means of:

1. Electricity generators’ generating units;

2. transmission system control devices;

3. control devices belonging to customers connected to the transmission system.

(2) The PS operator shall plan voltage control on the basis of the following criteria:

1. permissible voltage limits in the transmission system nodes;

2. stability margin;

3. minimal losses of active electrical energy in the transmission system.

(3) Delivery of participation in voltage control service is defined by the following indicators:

1. reactive power operation range – determined by the power curve of the synchronous generator / compensating device;

2. precision of maintaining the voltage assigned as follows:

a) ± 7,5 kV for the 750 kV power grid;

b) ± 4 kV for the 400 kV power grid;

c) ± 3 kV for the 220 kV power grid;

d) ± 2 kV for the 110 kV power grid;

(4) Voltage control quality in the connection point shall be evaluated by the operating voltage deviations from assigned values and utilization of the reactive power range.

(5) The transmission system Users shall mandatorily participate in voltage control in the transmission system.

Section V

Tertiary (Minute) Reserve Planning

Art. 101. The purpose of tertiary control is:

1. to maintain and recover the required secondary control reserve when it is partially or completely utilized;

2. merit order distribution of the operating capacity and of the secondary control reserve among the individual generators by means of automatic or manual change of the operational point of the generating units.

Art. 102. The required tertiary control reserve and its dispatching is performed by the PS operator.

Art. 103. (1) The tertiary control reserve involves the following means:

1. the part of the spinning reserve of synchronous generators operating in parallel to the power system, that has not been included in the primary and secondary control reserve;

2. synchronous generators that can be put in parallel and loaded;

3. range of electrical load demand variation that can be effected upon the dispatcher's instruction;

4. standby capacity in other power systems that can be made available upon the PS operator's request.

(2) The reserve under para.1 items 1, 2 and 3 is utilized through amendment of the plan and generation and demand schedules inside the zone of control, and the reserve under para.1, item 4 - through amendment of the schedule of interchange with other power systems.

(3) The means of tertiary control indicated in para.1 shall be activated for a time period not exceeding 15 minutes as from the moment of the dispatcher's instruction.

(4) The tertiary control reserve shall not include:

1. generating sources shut down for maintenance and in forced outage;

2. ranges of generating sources subject to restrictions upon the capacity arising from conditions of the environment such as cooling water temperature in summer, emissions, etc.;

3. ranges of hydro-power stations and pumped-storage power station subject to restrictions upon the capacity arising from hydrological conditions or restrictions upon the volume of water discharged;

4. generating sources and customers' facilities for the ranges subject to restrictions related to the operating modes of the power transmission and/or power distribution networks.

Art. 104. (1) The tertiary control reserve is made available through:

1. Contracts for utilzation of the availability of condensing power plants purchased by the public provider for the reserve under Art. 103, para.1, item 1;

2. Contracts for use of the public provider's hydro-power stations and pumped-storage HPS under Art. 103, para.1, items 1 and 2 as tertiary control reserve where the power plants have not presented proposals or notifications in the balancing market;

3. Proposals or notifications quests presented in the balancing power market by market participants in conformity with the procedures described in the Electricity Trading Rules, for the reserve under Art. 103, para.1, items 1, 2 and 3.

4. Contracts with operators of other power systems for provision of reserve under Art. 103, para.1, item 4.

Art. 105. (1) Activation of the reserve for tertiary control of the means under Art. 103, para.1, items 1 and 2 may be done from the dispatching center of the PS operator without any intervention of the power plant shift operators where the generators are equipped with remote control devices.

(2) The reserve for tertiary control of the means under Art. 103, para.1, items 1 and 2 not equipped with remote control devices and means under Art. 103, para.1, item 3 is activated with the intervention of the shift operators at the respective power facilities on the basis of dispatch instructions.

(3) The reserve for tertiary control of the means under Art. 103, para.1, item 4 is activated after coordination with the PS operators from the synchronous zone through amendment of the interchange schedule.

(4) After activation, the means under Art. 103, para.1, item 2 can be introduced in the secondary load and frequency control for the purpose of restoration of the secondary control reserve.

Art. 106. (1) The tertiary control reserve is planned in coordination with planning of the reserve for reliability of electricity supply to the customers.

(2) The required daily quantity of tertiary control reserve is determined by the following empirical formula:

$P_t = 1,1\ (P_{1000} - P_{ALLS})$, MW, where:

P_{1000} is the capacity of the largest unit for the day;

P_{ALLS} is planned reduction of the PS load capacity due to operation of the Automatic Load Limiting System (ALLS) upon shutting down of a 1000 MW rated capacity unit at the nuclear power plant; P_{ALLS} is zero when P_{1000} is less than 500 MW.

(3) The margin factor for tertiary control is assumed to be the same as in the determination of the мощностното число for secondary control K_{ri}.

Art. 107. (1) All sources used for tertiary control shall be listed by priority within the time limits and in the manner indicated in Chapter Five, Section III of the Electriciry Trading Rules.

(2) The priority lists under para.1 are needed for:

1. compensation for generator capacity shortage in the power system;
2. compensation for generator capacity surplus in the power system;

(3) The technical parameters characterizing the dynamics of the active power variation process from each source of balancing power in conformity with Chapter Five, Section IV of the Electricity Trading Rules, constitute an integral part of the priority lists under para.1.

Section VI

Planning of the Transmission System Operation Mode

Art. 108. The purpose of planning the transmission system operation mode is to create the required conditions for normal and cost saving operation of the power system and to carry out the needed schedules and forced-outage maintenance of the facilities without violating the reliability criteria indicated in Art. 12. Such planning involves:

1. development of annual programs for maintenance of the transmission system facilities;
2. day-to-day planning.

Art. 109. The PS operator, in coordination with the transmission service provider, shall develop a program for maintenance of the transmission system facilities for the current calendar year.

Art. 110. The annual maintenance program for transmission system facilities shall indicate the date of start, time period of the maintenance works during which the facility will not be available, and the mandatory conditions that shall be met upon putting the facility out of operation, if any.

Art. 111. The following priorities shall be adhered to in the process of developing the program:

1. conformity with the reliability criteria indicated in Art. 12;
2. harmonized electricity supply long-term contracts and schedules;
3. maintenance program for electricity generators' generating capacities;
4. harmonized external partners' contracts and programs for maintenance or construction of new facilities.

Art. 112. The annual facility maintenance program shall be developed by the following procedure:

1. before the end of October of the calendar year preceding the planning year, the transmission system Users shall send to the transmission service provider their applications for repair of facilities in their grids as well as any other specific requirements that shall be taken into consideration in the process of developing the annual program for maintenance of transmission system facilities;

2. before the end of November of the same calendar year the transmission service provider shall draw up a proposal for annual maintenance program indicating:

    a) the dispatch denomination of the facility to be put out of operation for maintenance;

    b) initial date and time required for maintenance;

    c) other conditions or requirements, if any.

3. By the end of December of the calendar year preceding the planning year, the PS operator, in coordination with the transmission service provider, shall develop the annual facility maintenance program by adhering to the priorities indicated in Art. 111. The harmonized annual maintenance program for transmission system facilities shall be placed at the disposal of all transmission system Users.

4. The program for maintenance of transmission system components of inter-system significance shall be drawn up in conformity with the agreements under Art. 1, para.2.

Art. 113. The annual maintenance program for the transmission system may be amended in the course of its implementation in the event of:

1. Onset of operation conditions that inhibit compliance with the reliability requirements indicated in Art. 12;
2. Mutual arrangements among the PS Operator, the transmission service provider and transmission system Users;
3. Force Majeure.

Art. 114. (1) The PS Operator shall define, on the basis of calculations and analyses, the maximum throughput of the transmission system in MW by quarters of an year and by main sectors.

(2) The quarters are defined as follows:

1. from December to February inclusive;
2. from March to May inclusive;
3. from June to August inclusive;
4. from September to November inclusive.

(3) The determined throughput values shall be published so as to be brought to the knowledge of all electricity market participants and to all transmission system Users.

Art. 115. (1) For the purposes of real-time control of the power system, the PS Operator shall perform operational planning of the transmission system operating mode.

(2) The operational planning shall cover a one-week period.

(3) The purpose of operational planning is to create the conditions needed for reliable and low-cost operation of the power system.

Art. 116. The composition of facilities and transmission system configuration shall be defined in the process of operational planning in the order of the following priorities:

1. conformity to the reliability criteria as per Art. 12 and low-cost operation in the forecast operation conditions during the planning period (forecast electric loads,

planned composition of the generating capacities, available transmission system facilities);

2. coordinated long-term planned electricity interchanges among transmission system Users;
3. annual maintenance program for the transmission system facilities;
4. short-term electricity interchanges among transmission system Users.

Art. 117. For operational planning purposes, the PS Operator shall receive the following information:

1. Schedules under bilateral contracts between transmission system Users participating in the liberated part of the market as ordered by the Electricity Trading Rules – from market participants;
2. Interchange schedules between Bulgaria and other power systems pursuant to concluded contracts – from the public provider;
3. Schedule of the coordinated electricity interchanges between the power system inside the synchronous zone – from the respective power system operators (PSO), in conformity with the agreements on parallel operation with other power systems;
4. Notifications of maintenance works on transmission system facilities in conformity with the annual program or for unscheduled maintenance – from the transmission service provider and transmission system Users;
5. The data needed for development of an updated mathematical model of the electric power system of partners within the synchronous zone to which Bulgaria operates in parallel, for computation of the expected load on the transmission system components and assessment of the admissibility and reliability of the operation of the Bulgarian power system – from power system operators in the synchronous zone, in conformity with UCTE requirements and recommendations.

Art. 118. (1) The Power System Operator shall perform daily one-day advance evaluation of the operation mode admissibility and reliability of the Bulgarian power system.

(2) In cases where the power system reliable operation criteria indicated in Art. 12 have not been met, the Power System Operator (PSO) has the right to refuse coordination of such electricity deliveries among transmission system Users that jeopardize its reliable operation and create prerequisites for occurrence of a system failure or damage of facilities.

Section VII

Defense Plan

Art. 119. The main purpose of the defense plan is to provide a protection mechanism preventing disintegration of the power system.

Art. 120. The defense plan shall define the procedures of protection against general system failures, their prevention and localization in conformity with UCTE Rules.

Art. 121. (1) An organization of defense against occurrence and development of general system failures as a result of emergency tripping of one or several components (generating units, power lines, etc.) shall be developed and implemented in each power system.

(2) Disturbances in one power system shall not be let to spread and have a negative effect on neighboring power systems operating in parallel.

(3) The PS Operator is responsible for the reliable and stable parallel operation of the power system and shall develop and coordinate with the rest of transmission system Users a defense plan as well as to coordinate its implementation and application in the process of work.

(4) The measures provided for in the Defense Plan shall be performed by all transmission system Users and are mandatory to them.

(5) The Defense Plan shall cover:

1. principles and organization of the defense system;
2. requirements to the technical protection devices used;
3. allocation of obligations and responsibilities among the PS Operator, the transmission service provider and transmission system Users for implementation of the Defense Plan.

Art. 122. (1) All power system facilities shall be equipped with relay protections ensuring tripping of the facility damaged as a result of short circuit.

(2) Relay protections shall have design and settings that meet the following requirements:

1. sensitivity – to be triggered by any type of short circuit in the protected area;
2. fast action – to disconnect the faulty component as quickly as possible in order to minimize the material damages and losses and to prevent disruption of the stable synchronous parallel operation of the power system or of one individual power plant;
3. selectivity – the relay protections shall disconnect only the facility affected by the short circuit in order to minimize the consequences of power supply interruption and to avoid disturbance of the stable synchronous parallel operation of the power system.

(3) In order to ensure the soonest possible reconnection of the power lines after isolation of the short circuit, they shall be equipped with automatic reclosing devices.

Art. 123. The requirements towards relay protection are presented in Chapter Three of these Rules.

Art. 124. (1) All power system facilities exposed to a risk of damage due to overloading by a current flow exceeding the permissible limit for such facility shall be equipped with overcurrent protection.

(2) Electrical facilities overloading of which can be avoided through operations within the permissible time limits do not have to be equipped with such protection.

(3) Overloading can be also interpreted as transmission of active power along interconnection and intra-system power lines exceeding the permissible maximum levels (critical power lines or cross-sections) determined by the condition to preserve the static and dynamic stability of the power system, part of it or an individual power plant.

(4) The PS Operator is obliged to determine, on the basis of its own studies, the critical power lines or critical cross-sections and to apply or require from individual Users connected to the transmission system, to ensure adequate accident-preventing control for elimination of the overload.

(5) In order to terminate the passing of active power flows above the permissible limits, accident-preventing active power automatic devices operating to disconnect the grid, shall be used.

Art. 125. (1) In order to terminate the out-of-step operation mode, all interconnection power lines through which parallel operation with other power systems is carried out, intra-system power lines (at the PS Operator’s discretion) and all generating units with capacity more than 150 MW shall be equipped with automatic devices for termination of out-of-step operation.

(2) Upon onset of an out-of-step operating mode, these automatic devices shall isolate the power system parts that operate non-synchronously, in order to confine further spreading of the disturbance.

Art. 126. (1) In the event of frequency deviation beyond the 49,5 Hz – 50,3 Hz range, accident-preventing control shall be undertaken in order to restore frequency to the permissible range.

(2) The power plants shall be able to operate at a frequency within the range 46,5 – 52,0 Hz until, as a result of accident-preventing control, frequency is restored to the limits under para.1.

(3) In the event of frequency decrease, the following accident-prevention control steps shall be taken:

49,5 – 49,0 Hz	Automatic tripping of pumps at the pumped-storage hydro-power station; Automatic or operational mobilization of the available spinning reserve at thermal and hydro-power plants; Automatic startup and synchronization of hydraulic-turbine generators at HPS;
49,0 – 48,0 Hz	*Underfrequency load shedding (UFLS)* UFLS means disconnection of electrical loads from the grid for the purpose of preventing further frequency decrease and restoring the balance between electricity generation and demand, at an acceptable level over 49,0 Hz until additional measures are undertaken to restore frequency to the permissible range. UFLS shall be performed by means of underfrequency relays installed in the transformer substations 110/MV that operate to disconnect MV terminals. UFLS is designed as follows: a) UFLS-I is designed for termination of any further frequency decrease and restoration of the generation – demand balance at frequency levels above 48,0 Hz. The time delay shall be the shortest possible, but not more than 0,5 s. The electrical loads shed by UFLS, shall be assigned to several steps in order to achieve smooth balance restoration and grading of disconnected consumers by significance (according to the declared category); b) UFLS-II is designed to restore frequency to the 40,0 Hz level after operation of UFLS-I. The time delay shall be sufficient to permit activation of the reserve for primary frequency control; c) Accelerated UFLS acting by the “frequency variation rate” criterion

	(d*f*/d*t*) and its purpose is to speed-up restoration of the generation – demand balance under conditions of significant active power shortages through shedding of any additional electrical loads at the very first moment of frequency decrease below 49,0 Hz. The total volume of electrical loads connected to the UFLS shall not be more than 60% of the total load in the power system at any point in time.

(4) Upon frequency increase, the following accident-prevention control steps shall be taken:

50,3-50,5 Hz	Automatic load shedding and tripping of HPS hydraulic-turbine generators
Over 50,5 Hz	Automatic load shedding of thermal power units

Art. 127. (1) In order to protect the electrical equipment in the transmission system from inadmissibly high voltages, all power lines of 400 kV or higher operating voltage shall be equipped with overvoltage protection.

(2) The overvoltage protection shall locate the power line that has caused voltage increase above the permissible limits and shall perform the respective control steps such as disconnection of capacitor banks, switching on of shunt reactors and disconnection of non-loaded power lines.

Art. 128. (1) The PS Operator, on the basis of its own studies, shall determine the points or areas of the grid where there is a risk of voltage drop and shall propose adequate accident control that shall be coordinated with the parties concerned: generators, distribution companies and customers connected too the transmission system.

(2) The accident-preventing control action may be switching off of shunt reactors, switching on of capacitor banks, disconnection of customers.

Art. 129. (1) In the event of emergency trip of a 1000 MW unit at Kozloduy NPP, the PS Operator shall use special centralized accident-control automatic devices.

(2) The automatic devices under para.1 shall:

1. in the mode of parallel operation with other power systems – to prevent overloads and isolation of the interconnection lines from overloads whereby the possibility to obtain emergency assistance from the neighbouring power systems can be secured;
2. in the mode of independent operation of the Bulgarian power system – to achieve active power balance at acceptable frequency level in the power system.

(3) The automatic devices under para.1 installed at Kozloduy NPP sends control instructions over PLC channels to the respective sites within the power system and operate to trip:

1. pumps at the Chaira Pumped-storage Hydro-Power Station;
2. customers whose technological process is not disturbed by short supply interruptions;

3. other customers as agreed with the transmission service provider.

(4) The PS Operator shall determine the volume of electrical load covered by the automatic devices in the 300 – 600 MW range depending on the operating conditions of the power system.

Art. 130. The dispatch centers and energy facilities shall be backed up with standby supply so as to preserve their operability until recovery of the normal power supply after severe accidents accompanied by loss of supply voltage in the control systems and telecommunication devices.

Section VIII

Restoration Plan

Art. 131. (1) The Restoration Plan applies to cases of:

1. break down of the Bulgarian power system into parts operating out-of-step, and disconnection of generation capacities and customers;
2. complete disintegration of the power system of Bulgaria.

(2) The Restoration Plan defines:

1. General principles of action on the part of the PS Operator, distribution network operators and personnel of the electrical facilities for power system restoration and allocation of functions and responsibilities among them;
2. A set of basic restoration scenarios upon the assumption of complete lack of voltage in the power system facilities that can be combines and apply to particular emergencies, including break down of the Bulgarian power system into parts operating out-of-step, and partial disintegration;
3. Order of priorities for restoration of the power system:
    a) auxiliary supply of the nuclear power plant;
    b) supply of customers where lack of supply creates risk to human health and lives and environmental pollution (zero category customers);
    c) auxiliary supply of thermal power plants;
    d) supply of customers where lack of supply leads to disruption of the functions of important infrastructure facilities in settlements, disorganization of complex technological processes (first category customers);
4. The main sources of supply in the process of power system restoration:
    a) neighbouring power systems;
    b) hydro-power stations with “black start” capability;
5. Emergency paths used for auxiliary supply of power plants.

Art. 132. On-line information support in the process of restoration shall be effected mainly by means of the Supervisory Control and Data Acquisition System (SCADA) for transmission system facilities and shall cover:

1. active and reactive power flows in the transmission system;
2. voltages and frequencies of bus systems and power lines;

3. position of the tap changers of system autotransformers;

4. active and reactive power of generating units;

5. capacities of compensating devices – shunt reactors and capacitor banks;

6. condition of the switching apparatus;

7. automatic operation of the relay protections at main transmission system components, automatic generation islanding, underfrequency load shedding;

8. malfunctions of the main communications;

9. main operating mode parameters of borderline substations of neighboring power systems.

Art. 133. The communications between the individual dispatching centers and between the dispatching centers and the main transmission system facilities shall be backed up.

Art. 134. SCADA shall be backed up with a system completely independent with respect to interconnection power lines and borderline substations.

Art. 135. The National Dispatching Center and the Regional Dispatching Centers shall be equipped shall be equipped with self-contained power supply sources that permit continuous performance of basic functions for at least 24 hours.

Art. 136. (1) shall be equipped with self-contained power supply sources that permit performance of operational switching and continuous operation of the protection, telemechanical and communication devices for at least 12 hours.

Art. 137. The plan shall be based on the following principles:

1. Restoration with the assistance of neighboring power systems;

2. Restoration by means of own sources (hydro-power stations) with capability for:

a) black start;

b) operation in isolated island mode;

c) synchronization of the isolated island with the power system;

3. Definition of emergency paths by the following criteria:

a) there shall be at least two paths from two independent sources to each facility;

b) all the time while the path is in the process of construction and extension, earthing of the neutral of the formed grid shall be secured;

c) the transmission capacity of the path shall ensure the minimum power required for recovery of the facility;

d) there shall be no self-excitation of the synchronous generators upon disconnection of an unloaded power line;

e) there shall be no dangerous voltage level increases in the nodes during construction of the path;

f) the relay protections shall have the required sensitivity;

g) throughout the path construction period, an adequate reserve of generating capacity shall be secured in order to ensure frequency under Art. 126, para.2 upon connection of the subsequent load;

h) the required ballast loads shall be ensured in the process of path construction and extension;

4. Preparation of the circuits at non-energized facilities – opening of all breakers except for:

a) the breakers on connection lines through which the facility is to receive voltage from the start sources;

b) HV breakers of the auxiliary supply transformers;

c) MV breakers of the auxiliary supply transformers;

5. Simultaneous construction of the emergency paths;

6. Control decentralization during the construction of emergency paths in conformity with the following requirements:

a) actions at the respective control level shall coincide with those in the absence of communications;

b) it shall be applied to a relatively small number of options differing primarily by their scope of activities;

c) each option shall be complete in form;

7. Construction of district distribution services around thermal power plants shall be performed in the following sequence:

a) power supply to the plant auxiliaries;

b) path expansion through connection of additional hydro-power stations (HPS) and loads;

c) startup and loading of turbo sets at the expense of connection of new loads and/or HPS load shedding for achievement of a reliable operating mode of the thermal power units;

d) maintenance of frequency at HPS with adequate power range and static characteristic;

8. Connection of independently operating district distribution services:

a) the district distribution services located in the territory of a Regional Dispatching Center shall be synchronized under the on-line control of the shift dispatcher at the respective RDC;

b) district distribution services located in the territories of neighboring Regional Dispatching Centers shall be synchronized under the on-line control of the shift dispatchers at the respective RDCs and under coordination of the shift dispatcher at the National Dispatching Center (NDC);

c) independently operating district distribution services of the power system of Bulgaria shall be synchronized with neighboring power systems under the on-line control of the shift dispatcher at the NDC.

9. Restoration of the parallel operation of the Power System:

a) restoration of the connected scheme of the transmission system;

b) restoration of the parallel operation of the Bulgarian power system with neighboring power systems;

c) restoration of the power supply to all customers with the assistance of neighboring power systems, as far as possible;

d) restoration of the planned operating mode.

Art. 138. Development of the Plan is an obligation of the Power System Operator.

Art. 139. (1) Coordination of the restoration plan:

1. carried out between the transmission service provider and the transmission system Users in conformity with the requirements of Art. 3, para.2, item 5;
2. carried out between the transmission service provider and the operators/transmission service providers of neighboring power systems.

(2) in the event of failure to reach agreement under para.1, item 1, the transmission service provider shall define the actions with respect to the restoration plan that are mandatory to the respective transmission system User who has expressed disagreement. In making such decision the transmission service provider shall take into account the respective User’s actual technical capabilities.

Art. 140. Circulation of the restoration plan:

1. The transmission service provider shall send to every transmission system User the parts of the official document that concern it;
2. Every transmission system User shall draw up a detailed local action plan for the shift operators at each of its facilities connected to the transmission system on the basis of the coordinated power system restoration plan.

Art. 141. Introduction of amendments in the restoration plan:

1. Each of the parties to the restoration plan has the right of initiative for proposals for amendments;
2. the Power System Operator shall propose introduction of amendments in the event of:

a) commissioning of new generating capacities;

b) connection of new customers to the transmission system;

c) modification of the transmission system configuration that affects the restoration plan;

3. each motivated proposal for amendment shall be discussed by the transmission service provider and the transmission system Users concerned in conformity with the requirements of Art. 3, para.2, item 5;
4. in the event that no agreement is reached, the transmission service provider shall define the action with respect to the restoration plan that are mandatory to the respective transmission system Users. In such decision making, the transmission service provider shall take into account the actual technical capabilities of the respective User;
5. the transmission service provider shall disseminate the amended document among all transmission system Users;
6. every transmission system User shall introduce amendments, where required, in the local plans for its facilities, on the basis of the amended power system restoration plan;
7. the Power System Operator shall revise the restoration plan every year.

Art. 142. Training of the shift operators in implementation of the restoration plan:

1. The transmission system operator is obliged to train its shift operators using a dispatching simulator of the power system operation;
2. the Power System Operator shall test in practice each emergency path down to the main power plants;
3. the Power System Operator shall annually carry out practical tests of parts of the emergency paths used for training of the personnel of facilities connected to the transmission system;
4. distribution network operators shall annually carry out practical tests of parts of the emergency paths used for training of their own personnel and the personnel of facilities connected to the distribution networks;
5. the Power System Operator, the distribution network operators and transmission system Users bear the responsibility for training of their own operation staff in implementation of the power system restoration plan.

Art. 143. External information exchange in the event of system accidents:

1. The Power System Operator, the distribution network operators and Users shall exchange the telephone numbers and names of the officials in charge of the organization and functioning of information stations that shall operate in the event of system accidents;

2. The Power System Operator shall inform the distribution network operators and the shift operators of the rest of transmission system Users in the event of a system accident;

3. The Power System Operator shall organize an information station that shall undertake the obligation to deliver information to:

a) the management of the transmission service provider;

b) the management of MEER and SERC;

c) the distribution network Users;

d) the mass media;

4. Every distribution company shall organize an information station that shall undertake the obligation to deliver information to:

a) the management of MEER and SERC;

b) the distribution network Users;

c) the mass media;

5. Every transmission system User may organize an information station that shall undertake the obligation to deliver information to:

a) the administrative and technical management;

b) the mass media;

6. Every distribution network User may organize an information station that shall undertake the obligation to deliver information to:

a) the administrative and technical management;

b) the mass media;

7. The information stations for external information exchange shall be organized separately by the operating teams that directly manage the power system restoration.

8. The information stations for external information exchange do not bear any responsibility for the power system operation and for the activities related to its restoration.

9. The Power System Operator and distribution network operators shall independently decide as to how long their information stations shall function and shall notify the Users concerned about their decision;

10. The Power System Operator may make a decision under item 9 upon restoration of the connected scheme of the transmission system and supply to at least 70% of the customers.

11. The distribution network operators may make a decision under item 9 upon restoration of the connected scheme of the respective distribution network and supply to at least 70% of the customers.

Chapter Six

POWER SYSTEM ON-LINE CONTROL

Section I

Generating Capacity Control

Art. 144. The main objectives of the Power System Operator and of the generators in relation to on-line control of generating capacities are:

1. To maintain the balance between demand and generation of active electrical power at the planned frequency levels and by the planned schedules of inter-system active power interchange.
2. To maintain the balance between demand and generation of reactive electrical power at the planned voltage levels in the transmission system nodes.
3. to provide the required reserve of generating capacities that guarantee the reliability and quality of parallel operation and power supply to the customers.
4. Control of bottlenecks in the transmission system.
5. Supervision of the assigned schedules of electric power and electrical energy generation.

Art. 145. The Power System Operator shall control the generating capacities of power generators who:

1. participate in the regulated portion of the electricity market;
2. participate in the balancing power market;
3. conclude contracts at free prices pursuant to Art. 100 of the Law on Energy;
4. provide ancillary services in conformity with the contracts concluded with the transmission service provider.

Art. 146. Control procedures:

1. The Power System Operator shall perform its obligations under Art. 145 by issuing dispatch instructions that shall include control signals from its automatic control systems, in order to:

a) keep the active power balance within the accepted system error limits of the control block in compliance with UCTE requirements;

b) assign an active power operational point for generators' power units including those that provide the service "participation in secondary control" in conformity with contracts concluded with the transmission service provider;

c) put generating capacities into/out of operation in conformity with planned electricity generation schedules;

d) activate notifications and proposals for balancing registered in the balancing power market for the purpose of maintaining the planned secondary control reserve;

e) maintain the planned primary control reserve in compliance with ancillary service contracts concluded with the transmission service provider;

f) change the voltage schedule of power plant buses connected to the transmission system upon deviations of the actual mode from the planned one;

g) activate notifications and proposals for balancing declared in the balancing market in order to overcome limitations in the transmission system;

2. Electricity generators shall perform their obligations under Art. 145:

a) observing the planned schedule of their generating units with respect to active power and variations defined by dispatch instructions;

b) observing the planned voltage schedule in the point of connection to the transmission system, and variations defined by dispatch instructions;

c) ancillary service providers shall comply to the provisions of ancillary service contracts with respect to their own generating units;

d) participants in the balancing power market shall follow its provisions and assure the operation of their generating units in conformity with the registered technical parameters.

3. The Power System Operator and electricity generators shall carry out automatic monitoring of:

a) performance of the planned schedules for generation of active electrical power and electrical energy and performance of the assignments of the automatic generation control system;

b) performance of the schedules of power plant bus voltages.

Art. 147. (1) The dispatcher's instructions shall be in accordance with:

1. The Regulation on Conditions and Procedure Governing the Work of Transmission and Distribution Network Operators as well as Shift Operators of Electric Power Facilities and Customers' Electrical Switchgears;

2. The Electricity Trading Rules.

(2) In the process of decision making and issuing of dispatch instructions, the Power System Operator shall assess the following factors:

1. Difference between planned and actual electricity demand;
2. Difference between planned and actual schedules of inter-system active power interchanges;

3. Registered balancing notifications and balancing proposals from balancing market participants;
4. Changes in the declared availability of electricity generators' generating units;
5. Changes in the transmission system condition;
6. Changes in the condition of distribution networks affecting the points of connection to the transmission system;
7. Condition of the respective types of generating capacity reserves that guarantee the reliability and quality of parallel operation and electricity supply to customers;
8. Actual performance of the schedules of power plant bus voltages;
9. Need for change of the voltage schedules of power plant buses connected to the transmission system for the purpose of securing the required reserve of active power;
10. Changes in the schedules of generators applying a combined cycle for generation of heat and electricity;
11. Changes in the schedules of generators using renewable sources for generation of electricity;
12. Changes in the planned schedules of electricity interchange with external trade partners;
13. Occurrence of disturbances in the power system operation;
14. Instructions issued through regulations and documents pursuant to the Regulation on Conditions and Procedure Governing the Work of Transmission and Distribution Network Operators as well as Shift Operators of Electric Power Facilities and Customers' Electrical Switchgears;
15. Any other factors relevant to the quality and reliability of the power system operation.

(3) The Dispatchers' instructions under normal operating conditions shall correspond to the declared technical characteristics of the generating units of electricity generators.

(4) The shift operators of electricity generators are obliged to follow these instructions. In cases where performance of such instructions would jeopardize the personnel's health and lives and would create a risk of facility damage or environmental pollution, the generators' operating staff shall promptly inform the Power System Operator about such consequences. The person issuing the instruction may countermand or confirm the instruction.

(5) In the event of disturbances in the power system the consequences of which are deterioration of the reliability and quality of parallel operation:

1. The Dispatcher may issue instructions for interruption of electricity market operation;

2. The Dispatcher's instructions may be in discrepancy with the declared technical characteristics of electricity generators' generating units; such instructions shall be issued for the purpose of preserving the integrity of the power system.

(6) The Dispatcher's instructions shall include:

1. Time for putting into/out of parallel;

2. Switching to/from primary control;

3. Parameters for participation in primary control;

4. Switching to/from secondary control;

5. Parameters for participation in secondary control;

6. Switching to/from standby / maintenance outage;

7. Variation of the active/reactive power load;

8. Change of the voltage schedule of power plant buses;

9. Activities related to assurance of safe conditions for repair and maintenance works related to the points of connection to the transmission system;

10. Emergency action;

11. Other activities relevant to on-line control of the power system.

(7) Issue and registering of the dispatcher's instructions:

1. The communications for issue and registering of dispatcher's instructions are specified in Chapter Three "Connection to the Transmission System".

2. The dispatcher's instructions shall be formulated in such a way as to minimize the probability of misunderstanding and errors;

3. The dispatcher's instructions shall be automatically recorded and archived;

4. The dispatcher's instructions shall be preserved for at least one month;

5. The confirmation of dispatcher's instructions receipt shall be sent immediately;

6. In cases where the dispatcher's instructions are issued over the telephone, the official receiving such instructions shall repeat them. The person issuing the instructions shall confirm if they have been understood correctly;

7. The consequences of failure to perform correctly issued dispatcher's instructions are regulated by the Regulation on Conditions and Procedure Governing the Work of Transmission and Distribution Network Operators as well as Shift Operators of Electric Power Facilities and Customers' Electrical Switchgears.

(8) Upon loss of communications and impossibility of issue/receipt of dispatcher's instructions:

1. The parties concerned shall undertake the actions required for restoration of the communications;

2. Electricity generators shall perform the active power, power plant bus voltage and frequency schedules as coordinated in advance;

3. New communication routes shall be organized as required whereupon the parties concerned shall mutually inform each other.

Section II

Load and frequency control

Art. 148. This Section regulates the Power System Operator's obligations in relation to load and frequency control and to provision of the required active power reserves in order to guarantee the quality and reliability of power system operation. The Power System Operator is coordinator of a control block with respect to primary and secondary frequency control within the framework of the North Accounting Coordination Center of UCTE.

Art. 149. Frequency control and active power control shall be viewed in the following aspects:

1. Primary frequency control;

2. Secondary load and frequency control;

3. Tertiary active power control;

4. Synchronization time adjustment.

Art. 150. (1) Primary control is an automatic function of the turbine governor to establish a frequency in the synchronous domain within definite limits.

(2) Maintenance of a reserve for primary control within the required volume and quality is a centrally coordinated system service provided by the Power System Operator and designed to assure the reliability and quality of operation in parallel.

(3) The following requirements apply to primary control:

1. The Power System Operator shall ensure a primary control reserve P_{pi} on the basis of the calculated disturbance P_{pu} in conformity with UCTE requirements defining the participation ratio

$$C_i = E_i/E_u,$$

Where:

E_i is the net annual electricity output in the individual control block;

E_u - the total net annual electricity output in the synchronous zone;

2. The reserve for primary control required by the Bulgarian power system is:

$$P_{pi} = C_i\ P_{pu},\ MW;$$

3. Full activation of the primary control reserve occurs at frequency deviation of $\Delta f = \pm 200$ mHz;

4. Controlling energy output to the synchronous zone for covering of the disturbance is: $\lambda_u = \Delta P_a/\Delta f$, MW/Hz and corresponds to the relationship of power shortage/surplus ΔP_a in the beginning of the disturbance and the quasi-stationary frequency deviation Δf occurring in consequence of the disturbance;

5. The controlling energy λ_i output in the control block of Bulgaria is calculated as:

$$\lambda_i = \Delta P_i/\Delta f,\ MW/Hz$$

where:

ΔP_i is the change of generating capacity in the control block of Bulgaria in response to the dirturbance.

(4) The generating units participating in primary control shall meet the following requirements:

1. Control range – at least +/- 5% of P_H;

2. Permissible insensitivity band ± 10 mHz;

3. Power variation rate 100% of the control range - linear within the limits of 30 s;

4. Turbine governor droop depending on the positive control range that shall be adjustable within the range 2 % to 10%;

5. The turbine governor shall perform speed control and power control functions;

6. The power activated through primary control shall be sustainable for a random length of time till restoration of the planned frequency value.

Art. 151. (1) The objective of secondary load and frequency control is to maintain the planned frequency level in the synchronous zone and the planned intersystem interchange of each individual control block after a disturbance.

(2) Secondary load and frequency control is a centralized system service provided by the Power System Operator.

(3) The more important characteristics of the secondary load and frequency control are:

1. Secondary load and frequency control in the control block of Bulgaria shall be performed automatically by a central frequency and interchange power regulator operating by the grid characteristic method. The central regulator shall be of a proportional-integrated type;

2. The central regulator shall periodically send an active power assignment that shall be performed by the TPP and HPS units included in the system for automatic frequency and power control;

3. The law of control is:

$$G = P_{пл} - P - K_{ri}(f_{пл} - f), \text{ MW},$$

where:

G is the system error – total secondary control deviation;

$P_{пл}$ and $f_{пл}$ are the planned values of interchange power and of frequency;

P and f – the respective instantaneous values;

K_{ri} is the power-frequency characteristic of the power system, MW/Hz and is determined annually within the framework of UCTE. ($K_{ri} = 1{,}1\ \lambda_{ri}$ where λ_{ri} is the controlling energy determined for the control block of Bulgaria). The power-frequency characteristics of the individual power systems within UCTE coordinated by the grid characteristic method are a guarantee that secondary control only of the power system where the disturbance has occurred will be activated for restoration of the frequency and exchange power to their planned levels;

4. The Power System Operator shall maintain a secondary control reserve pursuant to Art. 98 para.3, item 1;

5. The total variation rate of the output power of generators participating in the secondary control shall be adequate for the control purposes. It is defined in percentage of the nominal capacity of the generating unit and depends on the type of primary energy resource. The rate typical of gas power plants is 8% per minute, of hydro-power stations with compensating basins – 1.5% to 2.5% per second, for condensing power plants – from 2% to 4% per minute, and of lignite-fired thermal power plants – from 1% to 2% per minute;

6. The secondary control shall function continuously, in both small deviations of frequency and interchange power related to normal operation, and in large deviations related to loss of generation, load or interconnection line;

7. The secondary control shall not interfere with the primary control function.

8. The secondary load and frequency control shall be only used for compensation of instantaneous deviations of frequency and interchange power;

9. Restoration of frequency and interchange power shall start maximum 30 seconds after a disturbance and shall be finally completed before the 15^{th} minute;

10. When a generating unit participates simultaneously in the primary and secondary load and frequency control, the action of primary and secondary control shall be coordinated in such a manner as to achieve optimal response of the generating unit in accordance with its technical characteristics.

(4) Some of the more important requirements towards the automatic load and frequency control (LFC) system are as follows:

1. active power measurement precision 0,5 % - 1,5 % and frequency measurement precision 1,0 – 1,5 mHz;

2. secondary regulator cycle 1-2 s.

(5) The Power System Operator, in compliance with UCTE requirements, shall provide backup load and frequency measurements and capability for automatic switchover to backup measurement upon loss of the main one.

Art. 152. (1) The purpose of tertiary control is to maintain the tertiary control reserve within limits pursuant to Art. 98, para.3 by means of the tertiary reserve.

(2) The tertiary control of active power is a centrally coordinated system service.

(3) The following targets are achieved through tertiary control:

1. performance reliability of the secondary load and frequency control by securing the required active power reserve;

2. merit order allocation of the operating power and secondary control reserve among individual generators through automatic or manual change of the operational point of the generating units.

(4) The sources defined in Art. 104 participate in maintenance of the needed active power reserve for tertiary control.

Art. 153. (1) Participation in synchro-time adjustment in the synchronous zone of UCTE is an obligation of the Power System Operator.

(2) Operation at the medium frequency in the synchronous zone different from the rated frequency 50 Hz results in discrepancy between the synchronous and universal astronomical time. That deviation serves as performance indicator of the primary, secondary and tertiary control and shall not exceed 30 s.

(3) Its adjustment includes operation at planned frequency 49,99 Hz and 50,01 Hz depending on the direction of deviation over a 24-hour period.

(4) The following provisions apply to the second synchronous zone of UCTE within which the Bulgarian power system is currently operating:

1. At accumulated deviation exceeding +/- 80s, the plan in terms of frequency is 49,95/50,05 Hz respectively;

(5) Continuous monitoring of the synchronous time and astronomical time in the synchronous zone is performed by the accounting coordination center; the latter plans the frequency schedules as well.

Section III

Control of Balancing Power Sources

Art. 154. (1) The sources of balancing power are controlled by the shift operators of the Power System Operator at the NDC in conformity with the provisions and procedures indicated in Chapter Five, Section VI of the Electricity Trading Rules.

(2) The principle guiding the Power System Operator in the control of balancing power sources is continuous maintenance of an adequate amount of secondary control reserve.

Art. 155. (1) Whenever there is shortage of generating capacity in the power system, or part of the positive secondary control range has been spent, the operator shall:

1. deactivate the balancing power sources that have been activated until that moment, in accordance with the priority list for surplus compensation, if any, in an order reverse to the order of their activation;

2. activate balancing power sources in accordance with the priority list for shortage compensation in the order of their sequence.

(2) Whenever there is surplus of generating capacity in the power system, or part of the negative secondary control range has been spent, the operator shall:

1. deactivate the balancing power sources that have been activated until that moment, in accordance with the priority list for shortage compensation, if any, in an order reverse to the order of their activation;

2. activate balancing power sources in accordance with the priority list for surplus compensation in the order of their sequence.

(3) The Power System Operator shall keep record of any activation of a proposal for balancing or a notification of balancing and the subsequent instructions within the limits of their duration in a registration sheet containing every ordered deviation from the physical nomination and the moment of receipt of the instruction by the shift operators at the facility of the balancing power provider.

Art. 156. (1) The order of activation and deactivation of proposals and notifications of balancing may be changed in the course of execution by the Power System Operator:

1. whenever the technical parameters characterizing the dynamics of the active power variation process of the next balancing proposal or notification do not correspond to the need for active power increase or decrease in the power system;

2. in the event of drastic change of weather conditions that may result in unjustified loss of water power resources;

3. in the event of unforeseen restrictions in the transmission and/or distribution systems or possibility of such restriction as a consequence of activation of the next proposal or notification of balancing;

4. in emergencies where the place of the balancing power source with respect to the transmission and/or distribution systems is of significance;

5. when the PSO has preliminary and reliable information that some balancing power source cannot ensure the required variation of active power irrespective of its position in the priority lists and the issued instruction for activation;

6. in other cases by decision of the operator's personnel depending on the particular circumstances.

(2) In all cases with change of the order of activating the balancing power sources, the reasons for such change shall be entered in the registration sheets in conformity with Art. 155, para.3.

Section IV

Voltage Control in the Transmission System

Art. 157. (1) The Power System Operator is obliged to provide the system service "voltage regulation in the transmission system" on the basis of the following principles:

1. Voltage maintenance in the transmission system nodes within permissible limits;

2. Keeping up an adequate level of stability during parallel operation of the power system;

3. Achievement of the required quality of electric power with respect to the "voltage variation range" criterion;

4. Minimum losses of active power.

Art. 158. Voltage control procedures:

1. The Power System Operator shall issue dispatching instructions to the generators to:

a) revise the planned schedule with respect to voltage in the buses of power plants connected to the transmission network upon deviations of the planned transmission system mode from the actual one;

b) transition from "voltage maintenance" mode to "reactive power maintenance" mode by setting the required reactive power value.

2. The Power System Operator, in order to secure the reactive power reserve needed for implementation of the planned mode in terms of voltage, shall issue dispatching instructions for mode change of the control devices in the transmission system:

d) shunt reactors;

e) capacitor banks;

f) static compensators;

g) power autotransformers;

h) power lines;

3. The Power System Operator shall issue dispatching instructions to distribution network operators for:

a) amendment of the assigned schedule in terms of voltage or reactive power assigned to the generators connected to the distribution network for the purpose of maintaining the planned voltage levels in the respective point of interconnection of the distribution and transmission system;

b) on/off switching of capacitor banks connected to the respective distribution network.

4. The Power System Operator exercises supervision on the performance of schedules in terms of voltage in the points of User interconnection to the transmission system.

5. Electricity generators shall:

a) maintain the voltages in the points of interconnection to the transmission system in conformity with the planned schedule within the agreed limits;

b) promptly execute the dispatching instructions for change of the planned schedule in terms of voltage;

c) in emergencies, for the purpose of maintaining the assigned voltage/reactive power schedule, execute the dispatching instructions for reactive power increase that may require decrease of the generating unit active power without violating the declared technical characteristics of synchronous generators;

d) promptly execute the dispatching instructions for switching from the mode of maintaining an assigned voltage to a mode of maintaining the assigned reactive power;

e) the generating units shall operate with automatic excitation controls of synchronous generators and system stabilizers continuously set in an operating position;

f) exercise automatic supervision on the execution of assigned voltage schedules.

6. The distribution network operators shall follow the instructions of the Power System Operator with respect to voltage maintenance in the points of interconnection of the distribution network to the transmission system within the agreed limits;

7. Generators who operate thermal power plants with unit power of the generating units larger than 25 MVA, or hydro-power stations with total power of the generating sets larger than 10 MVA shall take part in voltage control in the points of connection to the transmission system in accordance with their technical capabilities.

Art. 159. All conditions for provision and receipt of the ancillary service of voltage control shall be regulated by an ancillary service contract concluded between the generator and the transmission service provider.

Section V

Control of Limitations in the Transmission System

(Congestion management)

Art. 160. The purpose of limitation control is to guarantee the reliable and failure-free operation of the transmission system while meeting, to the greatest extent possible, the electricity transmission requirements of transmission system Users.

Art. 161. In the process of real-time control of the power system the Power System Operator shall observe the maximum throughput of the transmission system as defined in Art. 114.

Art. 162. The Power System Operator shall accept notifications of electricity exchange among the Users within the permissible limits of the maximum throughput of the transmission system as defined in Art. 114.

Art. 163. Throughput limitations in the transmission system may arise:

1. In the process of coordination of the planned deliveries of electricity among Users when the maximum transmission system throughput limits are not observed;

2. Upon emergency trip of a transmission system component;

3. Upon emergency trip of a generator capacity in the power system.

Art. 164. (1) In the cases where the Power System Operator, in the process of the limitation forecast finds that limitations will arise in the transmission system, it shall undertake the required corrective measures in order to eliminate the limitations.

(2) The corrective measures shall be defined by the Power System Operator depending on their degree of efficiency and shall be promptly applied in order to minimize the risk of accident in the power system. Such measures can be:

1. Switching on standby components of the grid, if any;

2.Benchmarking of the transmission system;

3.Shutdown of the hydraulic turbo-alternators in pumping mode;

4. Activation of standby generating capacities;

5. Reduction or complete termination of the planned deliveries among transmission system Users.

Art. 165. Reduction or complete termination of planned deliveries shall be applied where no other efficient corrective measures can be implemented. The Power System Operator shall reduce or terminate planned deliveries until the limitation is eliminated, with equal treatment of all transmission system Users and complete transparency of the procedure in the following succession:

1. Planned deliveries with strongest effect on elimination of the limitation;

2. In the case of equivalent effect on elimination of the limitation, mitigation or limitation shall be applied in the reverse order of receipt.

Section VI

Demand Management

Art. 166. Demand management shall be implemented by the Power System Operator, by distribution network operators and by Users connected to the transmission system in the cases of disturbance of the quality and reliability of power system operation after the other available possibilities for restoration of the normal operating parameters have been utilized.

Art. 167. The purpose of demand management is to preserve the power system integrity and to localize the development of accidents such as:

1. frequency drop;
2. voltage drop;
3. overloading of transmission system components;
4. shortage of generating capacities.

Art. 168. Demand management encompasses procedures for on-line demand restriction and does not consider:

1. automatic load shedding by the accident control systems;
2. demand management procedures for a participant in the non-regulated portion of the market when its balancing

notification/proposal is based on variation of the electricity consumed.

Art. 169. The implementation of demand management shall assure equal treatment of the transmission system Users.

Art. 170. Demand management procedures:

1. Users connected to the transmission system shall participate in demand management under the effective contract concluded between an User and the transmission service provider and defining:

a) location and size of the load to be reduced;

b) name and telephone number of the official who will carry out demand reduction upon the Power System Operator's instruction;

c) time for performance of the agreed load shedding.

2. Distribution companies shall take part in demand management in the following form:

a) organize customer groups for pre-fault manual disconnection, without notice, in the points of connection to the transmission system;

b) coordinate, with the Power System Operator and distribution network operators, manual advance-notice disconnection of customers;

c) organize four load restriction groups each, for the purpose of advance-notice demand management;

d) the connections between generating capacities and electrical grids shall not be disturbed upon such disconnections;

e) The advance-notice demand management system is referred to in the Ordinance on Rationing, Temporary Interruption or Restriction of Electricity, Heat and Natural Gas Production or Supply;

f) The groups shall be formed in a manner permitting the fastest shutting down possible avoiding complicated switching operations in the electrical grids;

g) The location and size of these groups shall be chosen with consideration of the customer supply category;

h) The power system operator and distribution network operators shall annually coordinate the composition, grading and expected load of these groups;

i) The data about the load restriction groups shall be permanently at the disposal of operators and Users performing demand management.

3. Demand management by means of planned manual disconnection in the event of prolonged deficit or transmission system limitations:

a) the Power System Operator shall instruct the distribution network operators to restrict consumption throughout the territory of the country or in part of it after a pre-defined program;

b) the pre-defined program shall regulate the volume and periodicity of restrictions on customers assuring, to the highest degree possible, equal treatment under the existing operating conditions in the power system;

c) The distribution network operators shall strictly apply the program instructions and shall monitor compliance with it on the part of customers;

d) Upon establishing non-compliance on the part of customers with any instruction for restriction, the measures envisaged by the Ordinance on Rationing, Temporary Interruption or Restriction of Electricity, Heat and Natural Gas Production or Supply shall be applied;

4. Pre-fault manual disconnection of customer groups without notice in the event of unplanned shutdown of generating capacities exceeding the available reserve:

a) The Power System Operator shall instruct the distribution network operators to disconnect as large customer groups as required;

b) Disconnection shall be carried out in pre-defined consecutive steps;

c) In the disconnection process, the highest possible degree of equal treatment shall be provided to the customers under the existing operating conditions in the power system;

d) The distribution companies shall annually present to the Power System Operator a plan for pre-fault manual disconnection of customer groups without notice for approval;

5. Action coordination:

a) Where demand management is carried out by the distribution companies by order of the Power System Operator, in order to preserve its integrity, the planned customer groups shall be immediately disconnected by the distribution network operators;

b) Where demand management is carried out by the distribution companies in order to preserve the integrity of distribution networks, the planned customer groups shall be immediately disconnected by the distribution network operators.

Section VII

On-Line Information Exchange

Art. 171. This Code enables the Power System Operator, the transmission service provider and transmission system Users to establish a procedure for:

1. on-line information exchange under normal operating conditions;

2. exchange of information about disturbances in the power system and events in order that the possible risk arising from them can be analyzes and assessed and adequate measures can be undertaken by the respective party in order to preserve the reliability and integrity of the power system;

3. on-line provision of information by the Power System Operator about increased risk of abnormal modes and accidents, and issuing of instructions for their prevention.

Art. 172. (1) Information exchange shall provide opportunities for:

1. drawing conclusions from the on-line operation and/or accidents that shall be taken into account upon further corrective action;
2. facilitating assessment of the possible risk that may arise and determining adequate measures for assurance of operation reliability integrity of the power system.

(2) The requirements for information details shall be determined in the process of:

1. In-operation information acquisition;
2. System event reports;

3. Joint investigation of events;
4. Information recording and coordination during putting the facilities in and out of operation.

(3) In the course of information exchange the parties shall:

1. assure transparency and accuracy of information;

2. observe the required confidentiality where their trade interests are affected.

Art. 173. (1) Operative action in the course of which the parties mutually inform each other about:

1. Switchgear changeovers;
2. Synchronization / tripping of generator units;
3. Change of assignment for frequency and active power control;
4. Change of assignment for voltage control;
5. Others, related to power system control.

(2) The information exchanged shall be sufficiently detailed to describe the instruction or operative action in order to give the message recipient an opportunity to consider it and to assess the possible risk. It shall include the name of the person reporting the operative work or the instruction on behalf of the power system User or operator.

(3) The recipient may pose questions for clarification of the information and the informing party shall assure provision of the needed information.

Art. 174. (1) On-line information shall be delivered sufficient time before the beginning of the planned action so that the recipient would be able to consider it, to assess the possible risk and to undertake the required measures.

(2) On-line information can be delivered verbally over the telephone, or in writing. In the case of verbal on-line information the recipient shall repeat it to verify that the information has been understood correctly.

Art. 175. (1) Events on which information shall be provided:

1. facilities of Users or of the transmission service provider operating with deteriorated technical parameters and/or can create hazard to human health and lives and material damage;
2. any alarm signal or indication of abnormal operating conditions;
3. tripping or temporary changes in the performance of facilities belonging to Users or to the transmission service provider;
4. switching off or failures of the telecommunication, remote control and measuring systems;
5. increased risk of triggering of emergency automatic devices;
6. any disturbances of normal operation and tripping of major facilities;
7. any operation of relay protection and automatic devices;
8. power supply disturbance;
9. breaking of the coordinated schedule for active power and voltage;

10. loss of basic functions of SCADA;
11. incidents with people;
12. fires, environmental pollution and other emergencies that may have a negative impact on the normal power system operation;
13. occurrence of a nuclear or radiation incident or violation of the nuclear and radiation safety procedures that is manifested in lower reliability, safety or output power;
14. unusual weather or other conditions.

Art. 176. (1) Events that have a significant effect on the power system operation require joint investigation.

(2) Every party hereto has the right to request joint investigation.

(3) The request for joint investigation shall be made in writing.

(4) The joint investigation shall be organized by the parties concerned in order to establish the causes of the event, to analyze its development, to draw conclusions and outline the measures necessary for prevention of such events.

(5) The form and procedure of joint investigation of a particular event shall be agreed upon in advance by the parties concerned.

(6) Independent experts may be invited for the joint investigation by mutial agreement between the parties. The results of the independent investigation shall be recorded in a report.

Art. 177. Events subject to joint investigation:

1. Manual or automatic tripping of large generating capacity;
2. Voltages beyond the permissible limits;
3. Frequency, beyond permissible limits;
4. Disturbance of the static/dynamic stability of the transmission system;
5. Overloads and tripping of transmission system components;
6. Other events significant to the parties.

Art. 178. The minimum set of data that shall be entered in the record:

1. Time and date of accident;
2. Exact dispatching title and owner of the facilities and sites affected;
3. Accident description – onset and development;
4. Technical parameters of the facilities mode before the accident;
5. Technical parameters of the facilities mode during the accident;
6. Capacity of customers with interrupted power supply, MW;
7. Capacity of customers with interrupted or changed power output, MW;
8. Length of interruption;
9. Unsupplied / non-generated electricity;
10. Analysis of the causes for onset and development of the incident;
11. Conclusions and recommended measures;

12. Expected time and date of putting the affected facilities into operation.

Chapter Seven
SAFETY COORDINATION

Art. 179. Safety coordination shall assure safe conditions for performance of works by the transmission service provider and/or Users at or near the point of connection to the transmission system when one party's safety is assured by the other party.

Art. 180. In the process of safety coordination, the provisions of the Health and Safe Conditions of Work Act (promulgated in State Gazette No. 124/1997) and the Regulation on Safety of Works at Switchgears of Power Generation and District Heating Plants and Power Lines (promulgated in State Gazette No. 34/2004) shall be mandatory.

Art. 181. Safety Coordination procedures:

1. The transmission service provider and transmission system Users shall make available to each other local safety regulations and safety procedures concerning their facilities in and near the points of connection to the transmission system;
2. The local safety regulations and safety procedures shall not contravene the Regulation on Safety of Works at Switchgears of Power Generation and District Heating Plants and Power Lines. They may supplement the measures provided in it taking into account the specificities of connection of Users' systems to the transmission system;
3. The parties concerned shall coordinate among themselves the respective local safety regulations for each point of connection;
4. Coordination of local safety regulations by the parties concerned shall be done officially in writing;
5. In the event that one of the parties wishes to change the local safety regulations that apply to its facilities in and near the point of connection, it shall inform the other party in writing substantiating the necessity for the change proposed;
6. New local regulations shall be coordinated between the parties concerned officially and in writing, without undue delay;
7. The local safety regulations for each point of connection of the switchgears/systems of transmission system Users shall be presented to the PS Operator by the transmission system Users;
8. The transmission service provider and the respective User shall appoint officials in charge of safety for each point of connection that shall be responsible for coordination and implementation of safety measures during works requiring foolproofing of the facilities;
9. The same person may be in charge of more than one points of connection;
10. Lists with the names of persons in charge of safety and their occupational safety qualification group for each point of connection shall be exchanged between the transmission service provider and Users. The parties concerned shall be notified of any changes in these lists in the shortest time possible;
11. Safety measure implementation:

a) The requesting party that intends to work at facilities in or near the point of connection to the transmission system shall apply to the PS Operator with the request for putting such facility out of operation;

b) After such permission is granted, the person in charge of safety of the requesting party shall issue a written Work Order defining the necessary safety measures in conformity with the Regulation on Safety of Works at Switchgears of Power Generation and District Heating Plants and Power Lines and the coordinated local safety regulations. The form of a written work order is determined by the safety regulation;

c) The PS Operator shall grant to the performing party a permission for implementation of the safety measures indicated in the written Work Order;

12. Registration of safety measures by the requesting party and access to work:

a) After performing the ordered safety measures, the performing party shall inform the requesting party directly or through the PS Operator;

b) The requesting party, after receipt of the performing party’s information, shall fill the respective field in the written Work Order where it shall enter the measures implemented, read it to the performing party and receive written confirmation of the correctness of the safety measures performed;

c) The requesting party’s person in charge of safety, after signing the written Work Order certifying performance of the ordered safety measures, shall allow the respective personnel access for performance of the planned works.

13. Completion of works:

a) After completion of the works the requesting party’s person in charge of safety shall guide the maintenance crew out of the work site and shall inform the Power System Operator and the performing party directly or through the PS Operator;

b) The parties shall record the time and finalize the completion of works by entries in the shift logbooks and in the written Work Order;

14. Establishment of a normal circuit of the transmission system:

a) The Power System Operator shall issue dispatching instructions to the shift operators of the parties concerned to perform the required switching operations;

b) All switching operations for restoration of the complete transmission system circuit shall be recorded in the sequence of their performance in the shift logbooks of the parties concerned;

15. The safety-related documentation shall be kept in conformity with the Regulation on Safety of Works at Switchgears of Power Generation and District Heating Plants and Power Lines.

Chapter Eight

MANAGEMENT OF THE POWER SYSTEM QUALITY OF OPERATION

Art. 182. This Code regulates the procedures for managing the quality of operation of the power system.

Art. 183. Management of the quality of operation of the power system involves:

1. Managing the quality of ancillary services provided by transmission system Users;
2. Managing the quality of system services provided by the Power System Operator.

Art. 184. Evaluation of the quality of provided ancillary services is a continuous process and shall be performed by the Power System Operator by the indicators and criteria as indicated in Chapter Five, Section IV and Section VIII. The following procedure shall be applied:

1. Proving the quality of service provided by means of tests conducted upon commissioning of new facilities or after repairs;
2. Monitoring of the power system in the process of normal operation in conformity with the defines indicators and quality criteria;
3. Analysis of the response of the power system and of the affected equipment of transmission system Users upon disturbances or accidents in the power system;
4. On-site inspections on the Power System Operator's initiative.

Art. 185. The potential for provision of ancillary services shall be proven through tests by the provider of the service to the Power System Operator. The tests shall be carried out after a program developed by the Power System Operator and reviewed by the User concerned.

Art. 186. The quality of provided ancillary services is controlled by means of:

1. Supervisory Control and Data Acquisition System (SCADA) of the Power System Operator;
3. Supervisory Control and Data Acquisition System (SCADA) of the transmission system User, if the latter has any;
4. Installed devices for metering electric power amounts;
5. Power System Operator's recording equipment;
6. Transmission system User's recording equipment, if it has any;
7. Any other relevant devices.

Art. 187. In the process of power system operation, the Power System Operator shall continuously monitor:

1. The quality of primary control according to the criteria indicated in Chapter Five, Section IV;
2. Quality of participation of power units in the secondary load and frequency control according to the criteria indicated in Chapter Five, Section IV. The Power System Operator's SCADA system automatically calculates the integral error within a 3-minute interval, conditioned by the inaccuracy with which the respective generating unit performs the central regulator's assignment. When the integral error exceeds the harmonized permissible value the automatic generation control system puts the respective generating unit out of secondary load and frequency control;
3. Quality of the tertiary control reserve according to the criteria indicated in Chapter Five, Section IV;

4. Quality of voltage control in the points of connection of Users to the transmission system according to the criteria indicated in Chapter Five, Section IV;
5. Performance of the protection measures ordered by it in conformity with the power system Defense Plan while continuously analyzing the operation of Users' protection devices during disturbances and emergencies in the power system;
6. Performance of the measures ordered by it in conformity with the power system Restoration Plan during commissioning of new facilities and after repairs;
7. The opportunity for participation in restoration of the power system after system accidents through tests and operator staff drills in conformity with the requirements in Chapter Five, Section VIII;

Art. 188. (1) When the service provided by a transmission system User does not meet the quality criteria, the Power System Operator shall refuse to accept such service;

(2) In these cases the Power System Operator shall organize receipt of the respective service from another provider while amending its ancillary service plan so as to guarantee the reliability and quality of power system operation.

Art. 189. An ancillary service provider who has declared its provision but is unable to provide it due to technical malfunctions in its facilities or for any other reasons, is obliged to cover the costs related to change of the organization of ancillary service provision in accordance with the ancillary service provision contract between the respective transmission system User and the Power System Operator.

Art. 190. In cases where activities stipulated in the Defense Plan and in the Restoration Plan are not performed, the Power System Operator has the right to terminate the respective User's access to the transmission system.

Art. 191. The quality of system services provided by the Power System Operator shall be evaluated by SERC.

Art. 192. (1) Before the end of March of the current year, the Power System Operator shall draw up a report analyzing the quality of power system operation during the preceding year and submit it to SERC.

(2) The analysis shall cover:

1. Quality of frequency control and inter-system interchange in normal operating conditions for each month and for the report year evaluated by:
    a) frequency histograms /bar charts/;
    b) mean frequency values;
    c) standard frequency deviations;
    d) standard frequency deviations of 90% and 99% probability;
    e) histograms of deviations from the inter-system interchange schedules;
    f) mean values of deviations from the inter-system interchange schedules;
    g) standard deviations from deviations from the inter-system interchange schedules;
    h) histogram of power system integral error;
    i) mean values of power system integral error;

j) standard deviation of power system integral error;

2. Quality of voltage control in the transmission system through voltage levels in predetermined setpoints for each month and for the report year evaluated by:

   a) Daily minimums and maximums;

   b) Voltage histograms on per-hour basis;

3. Controlling energy of the Bulgarian power system during disturbances in the synchronous zone outside the power system of Bulgaria;

5. Controlling energy and “trumpet” curve during disturbance in the Bulgarian power system of the type:

   $H(t) = f_0 +/- A.e^{-t/T}$,

   Where:

   $A = 1{,}2\ \Delta f_2$;

   Δf_2 is the maximum deviation of frequency from its setting as a result of the disturbance;

   $T = 900/\ln(A/d)$;

   $d = +/-20$ mHz;

   f_0 – the assigned frequency.

Secondary control is considered successful where, during compensation for a large disturbance, the system frequency stays within the trumpet curve.

Art. 193. In the event of unsatisfactory quality of power system control, SERC shall issue instructions to the Power System Operator for remedial measures and the schedule of their implementation.

Chapter Nine

SYSTEM TESTS

Art. 194. This Code assures personnel safety, reliability of electric power supply, integrity of the power system and mitigation of potential economic losses of the affected parties during performance of system tests.

Art. 195. This Chapter regulates the system test procedures that have or may have an impact on the transmission system, transmission system Users’ systems or external partners.

Art. 196. Procedure for performance of system tests proposed by a transmission system User:

1. The User concerned shall send a written request to the Power System Operator containing information about the nature and purposes of proposed tests as well as the extent to which the User’s system/user’s facilities will be involved in the tests. The request shall be filed at least three months before the start of such tests with shutting down of generating capacities or loads over 50 MW;

2. After consideration of the request, the Power System Operator shall promptly and in writing demand additional information from the test proposer if it finds insufficient the information contained in the written request;

3. The Power System Operator is not obliged to undertake any steps before it has received the additional information demanded;
4. After the Power System Operator receives the required additional information, it shall define the other transmission system Users, beside the one proposing the tests, that will be affected by the system tests;
5. The Power System Operator shall appoint an official – Test Coordinator – who shall also be Chairman of the Test Committee:
    a) when, in the Power System Operator's judgement, the system tests proposed have or may have a significant impact on the transmission system, the Test Coordinator shall be a person of adequate qualification and experience in the performance of system tests, nominated by the Power System Operator;
    b) when, in the Power System Operator's judgement, the system tests proposed will not have a significant impact on the transmission system, the Test Coordinator may be a person of adequate qualification and experience in the performance of system tests nominated by the test proposer after coordinating the nomination with the Power System Operator;
6. The Power System Operator shall send a written notice ("advance notice") to the transmission system Users determined under item 4 and to the party proposing the tests. The advance notice shall contain:
    a) information about the nature and purposes of the tests proposed;
    b) the extent to which the proposing party's system/ facilities will be involved in the tests;
    c) list of transmission system Users determined under item 4;
    d) the system test proposer;
    e) invitation to the transmission system Users under item 4 to nominate their representative with the required qualification for the Test Committee if the Test Coordinator has informed the Power System Operator of the need for participation of representatives of the Users concerned in the Test Committee;
    f) The name of the Power System Operator's representative(s) in the Test Committee;
    g) Name of the Chairman of the Test Committee nominated by the Power System Operator or by the test proposer;
7. The Power System Operator shall send the advance notice maximum one month after receiving the system test request or after receipt of the additional information under item 2;
8. Replies to the invitation for nomination of representatives in the Test Committee shall be received by the Power System Operator maximum one month after sending the advance notice. The transmission system Users who have not replied within that time limit are not entitled to having their representatives in the Test Committee;
9. After expiration of the one-month term the Power System Operator shall form the Test Committee on the basis of nominations received and shall advise the

transmission system Users under item 4 and the test proposing party of the establishment of the Test Committee;

10. The Test Coordinator shall convene a meeting of the Test Committee maximum two weeks after its establishment. The following items shall be considered at that meeting:
    a) information on the nature and purpose of the tests proposed and other issues listed in the advance notice;
    b) operation risks and economic impacts of the proposed system tests;
    c) possibilities of combining the proposed system tests with repairs of generating units, transmission system components, or other tests planned in advance;
    d) impact of the system tests proposed on operation planning and generation unit dispatching;
11. The transmission service provider, the test proposer and the transmission system Users under item 4, irrespective whether represented in the Test Committee, are obliged, upon written inquiry, to provide information needed by the Committee in connection to the proposed system tests;
12. The Test Committee shall be convened to meetings by the Test Coordinator as frequently as required to meet its obligations;
13. Within one month after its first meeting the Test Committee shall prepare a report ("Report of Proposal") containing:
    a) Evaluation of the technical aspects of tests proposed;
    b) Allocation of costs related to the tests proposed among the parties concerned; the general principle, unless otherwise agreed, is that the costs shall be borne by the test proposer;
    c) Other issues the Committee finds relevant;
    d) Clearly worded proposal for conducting the system tests;
14. The Test Committee shall pass the resolutions on the Report of Proposal with consensus;
15. The Report of Proposal shall be sent without delay to the Power System Operator, to the test proposer and to transmission system Users under item 4;
16. Every recipient of the Report of Proposal shall send its written consent or arguments for its disagreement to the Test Coordinator maximum two weeks after receipt of the Report;
17. In the event of disapproval by one or more recipients, the Test Committee shall hold a meeting within the shortest time possible in order to assess the feasibility of changes in the tests that would satisfy the objections raised;
18. If the system tests proposed can be changed, the Test Committee shall draw up a revised report within two weeks after its meeting for review of the responses to the Report of Proposal and shall send it to the parties under item 15;
19. If a Report of Proposal / Revised Report is approved by all parties that have received it, within two weeks the Test Committee shall present to the Power System Operator, to the test proposer and to transmission system Users under item 4, a program (Test Program) containing:

a) A time schedule;
b) Switching sequence;
c) List of the personnel taking part in the tests;
d) Recording and monitoring devices;
e) Communications;
f) Safety measures;
g) Other matters found relevant by the Committee;

20. The Test Program shall obligate all parties under item 15 to act in conformity with the conditions of that program in connection with the tests proposed;
21. Any problems related to the system tests proposed that may arise after the issue of the Test Program shall be promptly sent in writing to the Test Coordinator. If the Coordinator decides that these problems require a change or postponement of the tests, it shall promptly advise the parties under item 15 in writing;
22. If the operating conditions of the power system on the date of system tests are of a kind to make a party under item 15 decide that it should postpone or suspend the start of tests, such party shall promptly inform the Test Coordinator of its grounds for such request. The Test Coordinator shall postpone or suspend the start of tests and appoint, with the parties under item 15, another suitable date for performance of the system tests. If the Test Coordinator fails to reach such agreement, it shall convene a meeting of the Test Committee in the shortest time possible in order to coordinate another suitable date for conducting the tests.
23. When any party under this Grid Code refuses to participate in system tests or fails to meet the obligations undertaken and that prevents the performance of planned system tests, the Power System Operator shall refer the matter to SERC. The State Energy Regulatory Commission shall pass a judgement that shall be binding to the parties concerned. SERC shall advise the Test Committee and the parties under item 15 of its decision;
24. Maximum 3 months from performance of the system tests, unless otherwise agreed, the test proposer shall send a written report ("Final Report") to the Power System Operator and to the other members of the Test Committee;
25. The Final Report shall include:

a) A description of the facilities tested;
b) Program of the tests conducted;
c) Results obtained;
d) Conclusions and recommendations.

26. The Test Committee shall discuss and approve the conclusions and recommendations of the Final Report within one month after its submittal after which it shall dissolve;
27. In some cases, at the Power System Operator's discretion, the request for system tests may be presented less than three months before the planned starting date of tests. In that case, after consulting the test proposer and the transmission system Users under item 4, the Power System Operator shall draw up a time schedule of the procedures under items 4 – 20.

Art. 197. Procedure for performance of system tests proposed by the transmission service provider:

1. The transmission service provider may conduct system tests in order to determine:
   a) Primary and secondary control efficiency;
   b) power system behavior during gradual (continuous-curve) load variations;
   c) power system behavior during sudden load variations;
   d) static and dynamic frequency characteristics and system factors;
   e) capability to provide the required conditions in terms of voltage and frequency in the transmission system setpoints and in the points of interconnection with other power systems;
   f) system stabilizer characteristics;
   g) other system-significant tests;
2. The Power System Operator shall draw up a tentative program defining:
   a) nature and purposes of the proposed tests;
   b) extent to which the transmission system/facilities of transmission system Users will participate in the tests or will be affected by them;
   c) Security measures;
   d) Safety measures;
3. The Power System Operator shall appoint an official to coordinate the tests in the authority of Test Committee Chairman. The Test Coordinator shall be a person of adequate qualification and experience in the performance of system tests;
4. The Power System Operator shall send a written notice ("advance notice") to the transmission system Users determined under item 2 b) at least six months before the date of planned system tests. The advance notice shall contain:
   a) information about the nature and purposes of the tests proposed;
   b) list of transmission system Users determined under item 2 b);
   c) the extent to which the systems/ facilities of the respective Users under item 2 b) will be involved in the tests;
   d) the system test proposer;
   e) invitation to the transmission system Users under item 2 b) to nominate their representative with the required qualification for the Test Committee if the Test Coordinator has informed the Power System Operator of the need for participation of representatives of the Users concerned in the Test Committee;
   f) name of the Power System Operator's representative(s) in the Test Committee;
   g) name of the Chairman of the Test Committee nominated by the Power System Operator;
5. Replies to the invitation for nomination of representatives in the Test Committee shall be received by the Power System Operator maximum one month after

sending the advance notice; transmission system Users who have not replied within that time limit shall not be entitled to having their representatives in the Test Committee;

6. After expiration of the one-month term the Power System Operator shall form the Test Committee on the basis of nominations received and shall advise the transmission system Users under item 2 b) of the establishment of the Test Committee;
7. The Test Coordinator shall convene a meeting of the Test Committee maximum two weeks after its establishment. The following items shall be considered at that meeting:
   a) information on the nature and purpose of the tests proposed and other issues listed in the advance notice;
   b) operation risks and economic impacts of the proposed system tests;
   c) possibilities of combining the proposed system tests with repairs of generating units, transmission system components, or other tests planned in advance;
   d) impact of the system tests proposed on operation planning and generation unit dispatching
8. The transmission service provider, the test proposer and the transmission system Users under item 2 b), irrespective whether represented in the Test Committee, are obliged, upon written inquiry, to provide information needed by the Committee in connection to the proposed system tests;
9. The Test Committee shall be convened to meetings by the Test Coordinator as frequently as required to meet its obligations;
10. Within one month after its first meeting the Test Committee shall prepare a report ("Report of Proposal") containing:
    a) Evaluation of the technical aspects of tests proposed;
    b) Allocation of costs related to the tests proposed among the parties concerned; the general principle, unless otherwise agreed, is that the costs shall be borne by the test proposer;
    c) Other issues the Committee finds relevant;
    d) Clearly worded proposal for conducting the system tests;
11. The Test Committee shall approve each resolution on the Report of Proposal with qualified majority;
12. The Report of Proposal shall be sent without delay to the Power System Operator and to transmission system Users under item 2 b);
13. Every recipient of the Report of Proposal shall send its written consent or arguments for its disagreement to the Test Coordinator maximum two weeks after receipt of the Report;
14. In the event of disapproval by one or more recipients, the Test Committee shall hold a meeting within the shortest time possible in order to assess the feasibility of changes in the tests that would satisfy the objections raised;

15. If the system tests proposed can be changed, the Test Committee shall draw up a revised report within two weeks after its meeting for review of the responses to the Report of Proposal and shall send it to the parties under item 12;
16. If a Report of Proposal / Revised Report is approved by all parties that have received it, within two weeks the Test Committee shall present to the Power System Operator and to transmission system Users under item 2 b), a program (Test Program) containing:
    a) A time schedule;
    b) Switching sequence;
    c) List of the personnel taking part in the tests;
    d) Recording and monitoring devices;
    e) Communications;
    f) Safety measures;
    g) Other matters found relevant by the Committee;
17. The Test Program shall obligate all parties under item 12 to act in conformity with the conditions of that program in connection with the tests proposed;
18. Any problems related to the system tests proposed that may arise after the issue of the Test Program shall be promptly sent in writing to the Test Coordinator. If the Coordinator decides that these problems require a change or postponement of the tests, it shall promptly advise the parties under item 12 in writing;
19. If the operating conditions of the power system on the date of system tests are of a kind to make a party under item 12 decide that it should postpone or suspend the start of tests, such party shall promptly inform the Test Coordinator of its grounds for such request. The Test Coordinator shall postpone or suspend the start of tests and appoint, with the parties under item 12, another suitable date for performance of the system tests. If the Test Coordinator fails to reach such agreement, it shall convene a meeting of the Test Committee in the shortest time possible in order to coordinate another suitable date for conducting the tests.
20. When any party under this Grid Code refuses to participate in system tests or fails to meet the obligations undertaken and that prevents the performance of planned system tests, the Power System Operator shall refer the matter to SERC. The State Energy Regulatory Commission shall pass a judgement that shall be binding to the parties concerned. SERC shall advise the Test Committee and the parties under item 12 of its decision;
21. Maximum 3 months from performance of the system tests, unless otherwise agreed, the Power System Operator shall send a written report ("Final Report") to the Test Committee;
22. The Final Report shall include:
    a) A description of the facilities tested;
    b) Program of the tests conducted;
    c) Results obtained;
    d) Conclusions and recommendations.

23. The Test Committee shall discuss and approve the conclusions and recommendations of the Final Report within one month after its submittal after which it shall dissolve;

24. In some cases, at the Power System Operator's discretion, a request for system tests may be presented less than three months before the planned starting date of tests. In that case, after consulting the test proposer and the transmission system Users under item 2 b), the Power System Operator shall draw up a time schedule of the procedures under items 4 – 17.

Chapter Ten

UNFORESEEN CIRCUMSTANCES

Art. 198. (1) If an emergency situation arises which the provisions of this Grid Code have not foreseen, the Power System Operator shall urgently, and by goodwill, consult promptly all affected transmission system Users in an effort to reach agreement as to what should be done.

Art. 199. (1) If an agreement is not reached within a short time between the Power System Operator and the affected transmission system Users with respect to the steps that shall be undertaken, the Power System Operator shall decide what is to be done if the security and safety of the power system are at stake, or the interests of other Users are affected.

(2) In making such decision, the Power System Operator shall take into consideration, as far as possible, the opinions of the affected transmission system Users.

Art. 200. Every User shall comply with all instructions issued by the Power System Operator after such decision to the extent that such instructions are consistent with the technical characteristics of the User's system.

Chapter Eleven

COMPLIANCE CONTROL

Art. 201. When a transmission system User cannot comply with the provisions of the Grid Code, it shall:

1. Promptly advise the Power System Operator about that;
2. File an application with SERC with a copy to the Power System Operator for exemption from compliance with some provisions indicating the reasons for such request as well as the time limits within which it will be able to comply with such provision.

Art. 202. The application for exemption from compliance shall contain:

1. The provision(s) of the Grid Code that are not met by the User concerned;
2. Exact definition of the User's facilities or systems for which exemption is requested;
3. Reasons of non-compliance with the indicated provisions and possible consequences of such non-compliance to other Users and to the safety, quality and reliability of power system operation;
4. The date by which the respective provisions will be met.

Art. 203. SERC shall consider the application in due time and may request the Power System Operator's opinion, if it finds it necessary.

Art. 204. (1) SERC shall pass a decision for exemption of the respective User from compliance with the Grid Code provisions indicated in the application if:

1. The concerned User's request is well grounded;
2. It will not have a negative impact on the safety, quality and reliability of power system operation;
3. It does not involve extra costs for operation of the transmission system;
4. It does not affect any other transmission system Users.

(2) In its decision to exempt the respective User from compliance SERC shall define:

1. the Grid Code provisions exemption from which is granted to the respective transmission system user;
2. the User's facilities or systems exemption for which is granted;
3. grounds on which the exemption is granted;
4. term of the exemption from compliance.

(3) When the conditions under para.1 item 3 are not met, SERC shall refuse exemption from compliance and shall inform the party concerned and the Power System Operator about the reasons of its refusal.

Art. 205. SERC shall notify the Power System Operator of the decision to grant permission for exemption from compliance a transmission system User;

Art. 206. The Power System Operator shall:

1. keep a register book of the granted exemptions from compliance of transmission system Users;
2. provide information from that register book upon a transmission system User's request.

Art. 207. Transmission system Users and the Power System Operator have the right to request from SERC revision of the permissions to grant exemption from compliance in the event of changes of the circumstances under which such permissions have been granted.

Art. 208. The control of compliance with this Code is part of the control of compliance with the terms and conditions of licenses issued by the State Energy Regulatory Commission .

Art. 209. Any disputes that may arise in connection with application of the provisions of this Grid Code shall be referred for resolution to the State Energy Regulatory Commission pursuant to the Law on Energy.

ADDITIONAL PROVISION

§ 1. Within the meaning of this Grid Code:

1. “Emergency path” (restoration path, path) is a combination of electrical facilities that permit transmission of electric power from a starting source to a thermal power plant or a nuclear power plant for supply of their auxiliaries or to a zero or first category user in the process of power system restoration.
2. “Automatic reclosing” is a device or built-in function of the relay protection of 110 kV, 220 kV, 400 kV and 750 kV power lines that automatically closes to connect the components disconnected from relay protection.
3. “Automatic generation islanding” is automatic division of a power system into predetermined parts around thermal power plants upon frequency decrease below a definite level. In the event that the frequency is not restored, the power plants are disconnected from the grid and supply solely their auxiliaries.
4. “Underfrequency load shedding” is automatic disconnection of predetermined loads in the distribution networks and in the grids of Users connected to the transmission system, upon frequency decrease. Load shedding is effected in steps ranging from 49,0 Hz to 48,0 Hz.
5. “Adequacy” is capability of the power system to supply the customers with electricity without interruption taking into account the scheduled and reasonably expected unscheduled shutdowns of power system components. Adequacy is an element of reliability.
6. “Active power” is an actual component of the full electrical power that can be transformed into another kind of power, for example mechanical, thermal, chemical, light, acoustic.
7. “Market participant balancing” is offsetting of the difference between the quantities of consumed/generated energy and the quantities according to the delivery schedules under concluded contracts, through supply of the lacking energy or receipt of the surplus energy in relation to the planned quantities pursuant to their operation schedules.
8. “Balancing group” is pooling of the Users that encompasses arbitrary parts of the power system precisely defined with respect to the points of power interchange with the transmission system and/or other balancing groups.
9. “Main transformer” (generator transformer) is a transformer connecting the electricity generator to the transmission system.
10. “Higher harmonics of a periodic variable” are sinusoidal quantities with frequency multiple of the basic frequency 50 Hz. Their presence, number and amplitudes are indicative of the asinusoidality of the periodic variable.
11. “Secondary control” is centralized automatic control of generating units in the control block based on utilization of the secondary control reserve to:
    a) maintain active power interchange with neighbouring control blocks and frequency in conformity with planned schedules;
    b) restoration of the planned frequency level in the event of deviations caused by loss of generating capacities/loads in the control block.

12. “Generating unit” is a set consisting of a turbine (with the control systems belonging to it), electricity generator (with the control systems belonging to it) and main transformer.
13. “Dynamic stability” is capability of the power system or a synchronous generator to go back, after a short circuit or large disturbances, to a stable condition close to the preceding one, passing through an attenuating transitional process.
14. “Defense plan” is the combination of engineering and organizational measures designed to prevent or localize disturbances or faults in order to avoid disintegration of the power system.
15. “Insensitivity band of a turbine governor” is a zone where the turbine governor does not respond to any frequency deviations from the preset value. It is determined by the design inaccuracies of the turbine governor and shall not exceed +/- 10 mHz.
16. “Control area” is a coherent part of the UCTE interconnected system (usually coincident with the territory of a company or a country), physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network, operated by a single Power System Operator. The CONTROL AREA may be a coherent part of a control block and shall have its own centralized load and frequency control.
17. “Availability factor” is:

    $K_r = T_{op}/(T_{op} + T_{unavail})$,

    Where:

    T_{op} is the time for which a generating unit has been operating during the considered period;

    $(T_{op} + T_{unavail})$ - the sum of time of operation and the time unavailability of a generating unit due to unscheduled maintenance.
18. “Control block” is a coherent part of the UCTE interconnected system (usually coincident with the territory of a company or a country), physically demarcated by the position of points for measurement of the interchanged power and energy to the neighbouring power systems. It is operated by a single Operator and consists of one or more CONTROL AREAS and has its own centralized load and frequency control.
19. “Short-term maintenance” is repair work that is not regularly planned and its length does not exceed 7 days.
20. “Reliability criterion n-1” is a rule according to which, upon tripping of one single power system component due to damage / failure (for example, a transmission line, transformer, generating unit or bus system) the components remaining in operation should be able to transfer the changed power flows in the transmission system caused by tripping of the single component.
21. “Reliability criterion n-2” is a rule according to which, upon tripping of two power system components due to damage / failure (for example, a transmission line, transformer, generating unit or bus system) the components remaining in operation should be able to transfer the changed power flows in the transmission system caused by tripping of the two components.

22. “Person in charge of balancing” is a person registered for participation in the balancing energy market pursuant to the Electricity Trading Rules who is in charge of coordination among all participants in a balancing group on the strength of a contract concluded among them.

23. “Dead band” of a turbine governor is an intentionally adjusted frequency range within which the turbine governor does not respond to any deviations of frequency from the scheduled (set) value.

24. “Reliability” is general performance of the elements of a power system that indicates the capability of electricity delivery to customers within accepted standards and in the amount desired.

25. “Reverse-sequence voltage” is one of the three symmetrical voltage components that exists solely in an asymmetrical three-phase system of sinusoidal voltages and is defined through the following complex mathematical expression:

    $U_2 = 1/3\ (\underline{U}_{L1} + a^2\ \underline{U}_{L2} + a\ \underline{U}_{L3})$, where:

    a is an operator of 120^o rotation;

    $\underline{U}_{L1}$, $\underline{U}_{L2}$ and $\underline{U}_{L3}$ are complex expressions of the three phase voltages.

26. “Voltage asymmetry” for a three-phase system non-uniformity in modulus and/or shift among the vectors of the three phase voltages to an angle different from $\pm 120^o$ electrical.

27. “Rated /nominal/ power” is the power indicated in the Test Certificate of an electrical machine/generating unit. If the rated power cannot be clearly determined by such document, the power level that can be achieved under normal operating conditions shall be taken as rated for that electrical machine/generating unit.

28. “Power plant operator” is a physical person performing operations for on-line control of the power plant.

29. “Person in charge of safety” is an official responsible for coordination and implementation of safety measures in the course of works requiring safeguarding of electrical facilities.

30. “Island mode” is implemented by generating units upon division of the power system into parts operating out of step. The generating units supply the loads (including their own auxiliaries), control frequency and voltage within the power system part where they are operating.

31. “Restoration plan” is a combination of engineering and organizational measures aiming to restore the normal operation of a power system after its partial or full disintegration.

32. “Transmission system User” is a physical or legal entity, owner of electricity generation, distribution or transformation systems, connected to the transmission system or electricity trader that uses the transmission system and the system services of the Power System Operator on the basis of a contract concluded with the transmission service provider.

33. “Remote backup principle” of the relay protection devices of a site/facility is the availability of relay protection at a neighbouring site that operates with an intentional delay upon the same types of faults.

34. “Full local backup” of the relay protection devices of a site/facility is the availability of more than one method (or means) of performing a required function.

35. “Primary frequency control” is an automatic decentralized function of the turbine governors of generating units synchronized with the power system that maintains the balance between generation and demand. Primary control adjusts the output of a generating unit as a consequence of a frequency deviation in the synchronous zone.

36. “System error” is the instantaneous difference between the actual and assigned value of the control area interchanges in accordance with the grid characteristic of that control area and frequency deviation from the planned level.

37. “Accounting coordination center” is an administrative structure authorized by the Control Blocks to perform settlement functions including:

a) archiving and checks of interchange schedules among the Control Blocks during the planning phase;

b) archiving

c) real-time monitoring

d) computation of

e) computation of

f) monitoring of system frequency quality

38. “Reactive power” is an imaginary component of the apparent power that creates and maintains the magnetic fields in alternating-current electrical machines. The reactive power is produced by the generators, synchronous compensating devices, static compensating devices and capacitors connected to the grid.

39. “Power system control energy” defines the response of each control block upon variation of the system frequency as a result of large disturbances.

40. “Independent operation mode with auxiliary supply” is implemented by the generating units upon their disconnection from the power system, whereupon they remain in operation just to supply their auxiliaries.

41. “System stabilizer” (stabilizer, stabilizing circuit) is a component of the automatic voltage regulators of the synchronous generators and is designed for damping the active power fluctuations in the frequency range 0,25 Hz – 3,0 Hz.

42. “System accident” is a case of disturbance of the system parameters, break-up of the power system into parts operating out of step or loss of voltage throughout the transmission system or parts of it whereupon some customers are cut off the power supply.

43. “System services” are services necessary for proper operation of the power system and provided by the Power System Operator, determining the reliability and quality of power supply.

44. “Disturbance” is an unplanned event that causes a change in the normal operating conditions of the power system.

45. “Auxiliaries of a generating unit” is the electrical power/energy required for operation of the auxiliary facilities or the generating unit.

46. “Static stability” is ability of the power system or of a synchronous generator to return to the preceding stable state after a small disturbance.
47. “Tertiary control” is automatic or manual change of the operational points of generating units for the purpose of restoring the reserve needed for secondary control within the required time.
48. “Tertiary reserve” (minute reserve) is power that can be activated automatically or manually in order to provide the reserve required for secondary control. That reserve shall be used in a manner contributing to restoration of the secondary control range as required. Restoration of the secondary control range shall be done within 15 minutes.
49. “Transmission system bottleneck” is a part of the grid encompassing one or several components with total throughput, taking into account the reliability criteria under Art. 12, lower than the electrical power that shall be transferred through that part of the grid.
50. “Voltage and Reactive power control” (VAR control) is maintenance of a definite voltage profile in the transmission system through balancing of the transmission system and users’ reactive power.
51. “Take or Pay condition” is a condition in a long-term power offtake contract concluded between the public provider and an investor - power plant owner. According to that condition the public provider is obliged to buy predetermined minimum amounts of electricity every month. If it fails to do so by its own fault, the public provider shall pay their cost to the investor.
52. “Stability” is a general term for static or dynamic stability. It means the capability of a power system to support synchronous operation of the generators.
53. “Power factor” (cos φ) is the relation of active to apparent power.
54. “Black start” is the capability of a generating unit or power plant to restore their operation without power supply to their auxiliaries from an external source;
55. The following abbreviations are used in this text:

Abbreviation	**Definition**
OSP	Out-of-step protection
ARC	Automatic reclosing
SG AEC	Synchronous generator automatic excitation control
AGI	Automatic generation islanding
UFLS	Underfrequency load shedding
PS	Power system
OVP	Overvoltage protection
ALLS	Automatic load limiting system
ALFC	Automatic load-frequency control
GUA, PPA, SSA	Auxiliaries (of a generating unit, power plant, substation)
BFP	Circuit breaker failure protection

SCADA	Supervisory Control and Data Acquisition System
UCTE	Union for Coordination of the Transmission of Electricity

FINAL PROVISION

§ 2. The Grid Code was drawn up on the grounds of Art. 83, para.1, item 4 of the Law on Energy and was accepted by the State Energy Regulatory Commission on the grounds of Art. 21, item 7 of the Law on Energy with Resolution No. П-2/04.06.2004, item 3.