Policy 1 — Load-Frequency Control and Performance

Policy Subsections

Introduction

The generation of power units that are connected to the UCTE network needs to be controlled and monitored for secure and high-quality operation of the SYNCHRONOUS AREAS. This generation control, the technical reserves and the corresponding performance measurements are essential to allow TSOs to perform daily operational business. Control actions are performed in different successive steps, each with different characteristics and qualities, and all depending on each other:

- PRIMARY CONTROL (see subsection A) starts within seconds as a joint action.
- SECONDARY CONTROL (see subsection B) replaces PRIMARY CONTROL after minutes by the responsible partner.
- TERTIARY CONTROL (see subsection C) frees SECONDARY CONTROL by re-scheduling generation by the responsible partner.
- Time control (see subsection D) corrects global TIME DEVIATIONS of the SYNCHRONOUS TIME on the long term as a joint action.

History of changes

v1.2	**draft**	**03.10.2002**	**SC**	**comments and changes of SC**
v1.1	**draft**	**23.09.2002**	**WG Op&Sec**	**comments and changes of WG**

Current status

This document summarises current UCTE rules and recommendations related to generation control and performance issues in a new structure, with additional items.

This policy will cancel and replace previous UCTE ground rules and recommendations regarding primary and secondary frequency and active power control, regulation reserves and correction of synchronous time.

A. Primary Control

[Appendix A1 – A: Primary Control]

Introduction

The objective of PRIMARY CONTROL is to maintain a balance between generation and consumption (demand) within the SYNCHRONOUS AREA, using turbine speed or power governors. By the joint action of all interconnected undertakings / TSOs, PRIMARY CONTROL aims the operational reliability for the power system of the SYNCHRONOUS AREA and stabilises the SYSTEM FREQUENCY at a stationary value after a disturbance or incident in the time-frame of seconds, but without restoring the reference values of SYSTEM FREQUENCY and power exchanges (see P1-B for SECONDARY CONTROL). Adequate PRIMARY CONTROL depends on generation resources made available by generation companies to the TSOs.

This policy section replaces the corresponding sections for primary control in the latest "UCPTE-Ground Rules concerning primary and secondary control of frequency and active power within the UCPTE", dated 1998.

Criteria

C1. **Nominal Set-Point Frequency**. Outside periods for the correction of SYNCHRONOUS TIME (see P1-D), the nominal set-point frequency value in the SYNCHRONOUS AREA is 50 Hz.

C2. **Frequency Deviations**. In case of a disturbance or an incident, a FREQUENCY DEVIATION will result. Different criteria are used to distinguish the size of the deviation:

- **C2.1.** **Calling up of Primary Control**. To avoid calling up of PRIMARY CONTROL in undisturbed operation at nominal set-point frequency, the FREQUENCY DEVIATION should not exceed ±20 mHz.
- **C2.2.** **Undisturbed Operation**. In case of undisturbed operation, the FREQUENCY DEVIATION does not exceed ±50 mHz.
- **C2.3.** **Maximum Quasi-Steady-State Frequency Deviation.** The quasi-steady-state FREQUENCY DEVIATION in the SYNCHRONOUS AREA must not exceed ±180 mHz (maximum permissible static FREQUENCY DEVIATION; under the condition of SELF-REGULATION OF THE LOAD according to C4).
- **C2.4.** **Minimum Instantaneous Frequency.** The instantaneous frequency must not fall below 49.2 Hz (that corresponds to -800 mHz as maximum permissible dynamic FREQUENCY DEVIATION from the nominal set-point frequency) in response to a shortfall in generation capacity equal or less than the reference incident according to C3.
- **C2.5.** **Load-Shedding Frequency Criterion**. Starting with a system frequency of 49.0 Hz (at or below), LOAD-SHEDDING (automatic or manual) starts. The detailed step-plan for load-shedding defines additional frequency criteria for further measures.

C3. **Reference Incident**. The maximum instantaneous deviation between generation and demand in the SYNCHRONOUS AREA (by the sudden loss of generation capacity, load-shedding / loss of load or interruption of power exchanges) to be handled by PRIMARY CONTROL in case of undisturbed operation depends on the size of the area and on the size of the largest generation unit or generation capacity connected to a single busbar located in that area[1].

- **C3.1.** **First Synchronous Zone**. In case of the first synchronous zone as in 2002 (and for larger SYNCHRONOUS AREAS, e.g. after reconnection of the second synchronous zone)

1 The final values used in the definition of the reference incidents are determined by the TSO-Forum and finally confirmed by the WG Operations and Security and the SC. The values given are currently under consideration.

the maximum power deviation to be handled is 3000 MW, assuming realistic characteristics concerning system reliability and size of loads and generation units (the system load for this SYNCHRONOUS AREA typically varies between 150 GW off-peak and 300 GW peak).

C3.2. ***Second Synchronous Zone***. *In case of the second synchronous zone of 2002, the maximum power deviation to be handled is 540 MW.*

C3.3. ***Other Synchronous Areas.*** *For other SYNCHRONOUS AREAS (UCTE SYNCHRONOUS AREAS), that are not connected to the main synchronous zone, the size of the reference incident needs to be defined in each particular case with respect to the size of the area and the size of the largest generation units located in that area.*

C3.4. **Observation Incident.** Incidents, such as the sudden loss of generation or load, that exceed 1000 MW are considered to be relevant for system observation.

C4. **Frequency Characteristics**.

C4.1. **Self-Regulation of Load.** The self-regulation of the load in all SYNCHRONOUS AREAS is assumed to be 1 %/Hz, that means load decrease of 1% in case of a frequency drop of 1 Hz.

C4.2. ***Overall Network Power Frequency Characteristic.*** *The overall NETWORK POWER FREQUENCY CHARACTERISTIC for the first synchronous zone is set to 18000 MW/Hz and for the second synchronous zone set to 3000 MW/Hz.*

C5. **Deployment Times of Primary Control Reserve.** The time for starting the action of PRIMARY CONTROL is a few seconds starting from the incident, the deployment time of 50 % or less of the total PRIMARY CONTROL RESERVE is at most 15 seconds and from 50 % to 100 % the maximum deployment time rises linearly to 30 seconds.

Requirements

R1. **Accuracy of Frequency Measurements**. For PRIMARY CONTROL, the accuracy of frequency measurements used in the PRIMARY CONTROLLERS must be better than or equal to 10 mHz.

R2. **Insensitivity of Controllers**. The insensitivity range of PRIMARY CONTROLLERS should not exceed ±10 mHz. Where dead bands exist in specific controllers, these must be offset within the CONTROL AREA / BLOCK concerned.

R3. **Primary Control Reserve**. PRIMARY CONTROL RESERVE need to have some characteristics to be usable for PRIMARY CONTROL.

R3.1. **Reserve Distribution**. In general, the PRIMARY CONTROL RESERVE must be physically distributed as evenly as possible between the different regions (usually between the CONTROL AREAS / BLOCKS) in the SYNCHRONOUS AREA (see also P1-B and the distribution procedure).

R3.2. **Total Size of Reserve**. The total PRIMARY CONTROL RESERVE (in MW) required for operation of a SYNCHRONOUS AREA is of the same size as the reference incident for that area (see C3).

R3.3. ***Availability of Reserves***. *In total and as a minimum, the full PRIMARY CONTROL RESERVE for each area must be available for 24 hours without interruption, not depending on the unit commitment in detail.*

R3.4. **Operational Usability of Reserves**. The entire PRIMARY CONTROL RESERVE (and each share of it) must be fully activated in response to a quasi-steady-state FREQUENCY DEVIATION of ±200 mHz or more.

R4. **Constant Network Power Frequency Characteristic**. In order to ensure that the principle of joint action is observed, the NETWORK POWER FREQUENCY CHARACTERISTICS of the various CONTROL AREAS must remain as constant as possible. This applies particularly to small

FREQUENCY DEVIATIONS, where the "dead bands" of generators may have an unacceptable influence upon the supply of PRIMARY CONTROL energy in the CONTROL AREAS concerned.

Standards

S1. **System Reliability**. In case of a first contingency or incident, such as the loss of generation or load or interruption of power exchanges in an undisturbed situation, PRIMARY CONTROL must maintain reliable system operation.

S2. **Primary Control Action.** The action of the individual generators performing PRIMARY CONTROL must have the following characteristics, to be ensured by the TSOs:

S2.1. **Adjustment of Generation**. Power generation under PRIMARY CONTROL must be constantly adjusted to follow changes of SYSTEM FREQUENCY.

S2.2. **Deployment**. Total PRIMARY CONTROL within the entire SYNCHRONOUS AREA (as well as within each CONTROL AREA / BLOCK) must follow the deployment times of PRIMARY CONTROL RESERVE (see C5). Each TSO must check the deployment times within his CONTROL AREA / BLOCK on a regular basis.

S2.3. **Duration of Delivery**. PRIMARY CONTROL POWER must be delivered until the power deviation is completely offset by the SECONDARY CONTROL RESERVE of the CONTROL AREA / BLOCK in which the power deviation has occurred (no longer than 15 minutes, see P1-B).

S3. **Primary Control Target.** During the undisturbed operation (see C2), a reference incident (see C3) must be offset by PRIMARY CONTROL alone, without the need for LOAD-SHEDDING in response to a FREQUENCY DEVIATION. In addition, where the self-regulating effect of the load is assumed according to C4, the FREQUENCY DEVIATION must not exceed the quasi-steady-state frequency deviation (see C2).

S4. **Principle of Joint Action.** PRIMARY CONTROL is based on the principle of joint action to ensure system reliability and interconnected operation. This includes an overall distribution of reserves and control actions, as determined and decided by the TSO-Forum on an annual basis for the next natural year.

S4.1. **Contributions to Primary Reserves**. Each CONTROL AREA / BLOCK must contribute to the PRIMARY CONTROL RESERVE as required. The respective shares are defined by multiplying the calculated reserve for the entire SYNCHRONOUS AREA (see R3 and P1-B) and the contribution coefficients of the various CONTROL AREAS / BLOCKS.

S4.2. **Contribution to Control.** Each CONTROL AREA / BLOCK must contribute to the correction of a disturbance in accordance with its respective contribution coefficient for PRIMARY CONTROL.

S4.3. **Contribution Coefficients.** The contribution coefficients must be determined and published annually for each CONTROL AREA / BLOCK. The contribution coefficients are binding for the corresponding interconnection partner / TSO for one year in advance. They are based on the share of the energy generated within one year in relation to the entire SYNCHRONOUS AREA.

Procedures

P1. **Contribution Coefficients**. The UCTE subgroup TSO-Forum determines and decides about the contribution coefficients of each CONTROL AREA / BLOCK for each SYNCHRONOUS ZONE on an annual basis and sets these values into operation on the 1st of January of the next year.

P2. **Observation of Outages**. Outages in production or consumption exceeding the size of the observation incident (see C3) are recorded for analysis. The corresponding information about location, time, size and type of the disturbance / incident is recorded and made available to the TSOs.

P3. **Performance Measurement**. The NETWORK POWER FREQUENCY CHARACTERISTIC is calculated in response to a disturbance (such as an observation incident), based on measurements of the SYSTEM FREQUENCY and other key values and on a statistical analysis.

Guidelines

G1. **Measurement Cycle for Primary Control**. Typically the cycle for measurements for PRIMARY CONTROL action must be in the range of 0,1s to 1s.

B. Secondary Control

[Appendix A1 – C: Automatic Generation Control]

[see also: UCPTE Rule 44: Control of active power in the grid of the UCPTE, 1990]

[see: UCPTE-Ground Rules concerning primary and secondary control of frequency and active power within the UCPTE, 1998]

[Appendix A1 – B: Automatic Generation Control]

Introduction

SECONDARY CONTROL maintains a balance between generation and consumption (DEMAND) within each CONTROL AREA / BLOCK, taking into account the EXCHANGE PROGRAMS, without impairing the PRIMARY CONTROL that is acting on the SYNCHRONOUS AREA level.

SECONDARY CONTROL makes use of a centralised automatic control modifying the active power set points of GENERATION SETS in the time frame of tens of seconds to typically 15 minutes. SECONDARY CONTROL is based on SECONDARY CONTROL RESERVES that are under automatic control.

Adequate SECONDARY CONTROL depends on generation resources made available by generation companies to the TSOs.

Criteria

C1. **Area Control Error**. In each CONTROL AREA, the AREA CONTROL ERROR (ACE) $G = P_{meas} - P_{prog} + K_{ri}\,(f_{meas} - f_0)$, must be kept close to zero permanently.

P_{meas} is the sum of the measured active power transfers on the TIE-LINES

P_{prog} is the resulting EXCHANGE PROGRAM with all the neighbouring CONTROL AREAS

K_{ri} is the K-FACTOR of the CONTROL AREA under consideration

$f_{means} - f_0$ is the difference between the measured SYSTEM FREQUENCY and the SET-POINT FREQUENCY.

C2. The SECONDARY CONTROL keeps the CONTROL AREA balance, in normal operating conditions, and contributes to restore it, in case of a sudden unbalance due to a GENERATION SET trip or LOAD trip. In case of a sudden large unbalance or a sustained LOAD variation, the TERTIARY CONTROL will be used in order to restore the SECONDARY CONTROL RESERVES.

C3. **Control Area Scale**. In each CONTROL AREA, sufficient controlable generation means or load control must be available in order to be able to keep the AREA CONTROL ERROR close to zero.

Requirements

R1. **Automatic controller.** In order to keep the ACE close to zero, the control must be automatic. In order to have no residual error, the controller must be of the integral type. Therefore, it will be of the PI (proportional-integral) type. The integral term must be bounded in order to have a non-windup controller, able to react immediately in case of change of sign of the ACE. The working of the secondary controller must be reliable.

R2. **Manual control** : In case of deficiency of the automatic control, a manual control has to be performed in order to keep the ACE close to zero.

R3. **SECONDARY CONTROL RESERVE**. An adequate control reserve must be available at all times to cover the loss of a generating unit. If the loss of the largest generating unit is not already covered by the requisite secondary control reserve, a tertiary control reserve (minute reserve) will be required to offset the shortfall. This tertiary reserve may be maintained outside the control area concerned.

R4. **Area demarcation**. Each CA is physically demarcated by the position of the points for measurement of the interchanged power to the remaining interconnected network.

R5. **Tie-line metering and measurement**. All tie-lines from a CA to adjacent CAs must have measurements and meters in operation to record the actual active (and reactive) power flow in MW (MVar) in real time and the energy in MWh in the time-frame for power exchanges that is used (one hour at the maximum).

All tie-line MW and MWh measurements should be telemetered to both control centers using common agreed primary equipment.

R6. **Accuracy of frequency and power measurements**. In SECONDARY CONTROL, the accuracy of frequency measurement must be better than XXX mHz and the accuracy of the active power measurement on each tie line must be better than 1.5 % of its rated value. The measurements cycle time must be lower than 2 s. Measurement cycle times, integration times and controller cycle times must be co-ordinated.

Substitute measurements and reserve equipment should be available. In this case, accuracy and cycle times may be temporarily impaired.

R7. **Transmission of measurements**. The measurements of the frequency and tie-line power flows must be transmitted on a reliable manner to the SECONDARY CONTROLLER (at least two ways recommended, with an alarm in case of deficiency of a data transmission). The transmission delay must be within a (to be defined) number of measurement cycles.

R8. **Data recording** - each TSO have to be equipped with a recording of all values needed for monitoring of the response of (primary and) secondary controllers and for analyse of the events in interconnected systems.

R9. **Responsible operator**. Each CONTROL AREA / BLOCK must be operated by an individual TSO that has the responsibility for the transmission system operation of this area (usually coincident with the territory of a company or a country), including the responsibility for availability, operation and provision of LOAD-FREQUENCY CONTROL to maintain the power interchange of his CONTROL AREA / BLOCK at the scheduled value and, consequently, to support the restoration of FREQUENCY DEVIATIONS in the interconnected network. Adequate LOAD-FREQUENCY CONTROL depends on generation resources made available by generation companies to the TSO.

R10. **Control hierarchy**. Each UCTE synchronous area consists of interconnected CONTROL AREAS with centralised AUTOMATIC GENERATION CONTROL. Each CONTROL AREA may divide up into sub-control areas that operate their own underlying generation control.

R11. **Jointly owned generation** shall be equipped with metering equipment providing function of pseudo tie line between two or more control areas.

Standards

S1. **SECONDARY RESERVE** : Each TSO operates sufficient generating capacity under automatic control to meet it's obligation to continuously balance its generation and Interchange schedules to it's load for the CONTROL AREA / BLOCK.

S2. **SECONDARY CONTROL use**. Secondary control must only be used in order to correct an overall system deviation G (ACE). Secondary control must not be used, e.g. to minimise unintentional electricity exchanges or to correct other imbalances.

S3. **Offset correction time.** One quality criterion for secondary control is the time taken for a control deviation to return to zero, i.e. the time taken to restore the frequency to its set point value and to restore power interchanges to their set point (programmed) values.

In practice, primary control action begins within a few seconds of a frequency deviation, and takes full effect not more than 30 seconds later. Frequency and power interchanges must begin to return to their set point values as a result of secondary control after 30 seconds, with the process of correction being completed after 15 minutes.

S4. **K-FACTOR.** In order to ensure that secondary control will only be called up in the control zone which is the source of the disturbance, all values for K_{ri} should, in theory, be equal to λ_i (if the Darrieus equation is to be satisfied). Due to the uncertainty of the self regulating effect of the load, the K_FACTOR K_{ri} will be taken equal to $1.1\ \lambda_i$, so that, most of the time, the SECONDARY CONTROL will help the PRIMARY CONTROL and not counteract it.

Under no circumstances should K_{ri} be modified during an incident, since this action would go against the principle of secondary control.

S5. **Controller type.** A network controller must have a proportional and an integral term (for an explanation of terms in the formula, see Appendix 1 B-4):

$$\Delta P_{di} = -\beta_i \bullet G_i - \frac{1}{T_{ri}} \int G_i \bullet dt$$

The control parameters β_i and T_{ti} must be set so that following conditions can be satisfied : frequency correction begins no more than 30 seconds after an incident and ends at most 15 minutes later, with a reasonable ramp rate and without overshoot. In case of a very large control deviation, the parameters β_i and T_{ti} may be adjusted automatically for a given period of time.

The control parameters β_i, and T_{ri} are closely linked. At present, values ranging from 0 to 50% may be set for the proportional term β_i of the area controller. The time constant represents the "tracking" speed of the secondary controller with which the controller activates the control power of participating generators. Values ranging from 50 to 200 seconds may be set for the time constant T_{ri} .

S6. **Set point values.** The frequency and agreed power interchange (programmed value) of the control area concerned are entered in the secondary controller as set point values. The procedure for the determination and adjustment of these set point values is described below.

S6.1. **Frequency set point value.** In order to synchronise network time with astronomical time, the set point frequency of 50 Hz may be varied within a range of ± 10 mHz over a period of 24 hours (see Policy 1, paragraph D).

S6.2. **Power interchange set point value.** The algebraic sum of the agreed hourly programme of interchange transfers between a control area and adjacent areas constitutes the power interchange set point of the control area secondary controller. In order to prevent excessive frequency deviations when programme changes occur, it is necessary that this jump is converted to a ramp with ramp period 10 minutes, starting 5 minutes before the agreed programme change and ending 5 minutes later (see appendix 1 B-6). This value may be adjusted as required.

In order to prevent unintentional frequency deviations and major control deviations under undisturbed conditions, system operators will be required to maintain careful compliance with times for programme changes, particularly where changes in the interchange programme of several hundred MW are involved. In particular, care must be taken to ensure that generating capacity is brought on line or disconnected on a staggered basis, particularly for tariff changes at 6 a.m. and 10 p.m.

A substantial change in scheduling or the scheduled modification of power plant operation must not have a negative impact upon system operation of the type which might be associated e.g. with a disturbance.

Guidelines

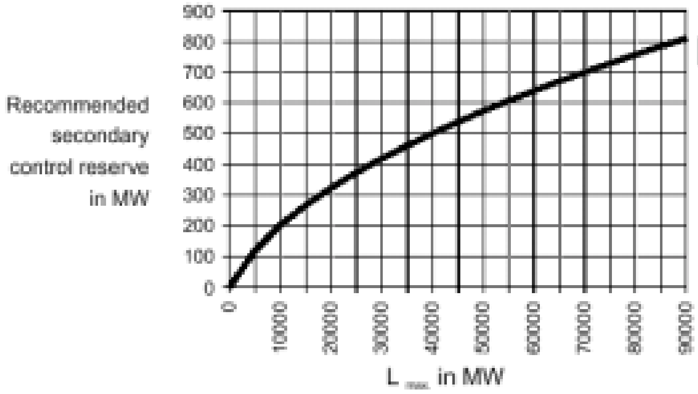
G1. Recommended secondary control reserve R (positive element of secondary control range). In control areas of different sizes, load variations of varying magnitude must be corrected within approximately 15 minutes. To this end, the following values (derived from the curve shown in the figure below) are recommended:

$$R = \sqrt{a\, L_{\max} + b^2} - b$$

R= the recommended secondary control reserve in MW

L_{max}= the maximum anticipated consumer load in MW for the control area over the period considered.

The parameters a and b are established empirically with the following values : a = 10 MW and b = 150 MW



C. Tertiary Control

Introduction

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D. Time Control

[Appendix A1-E: Time Control]

Introduction

The objective of this policy is to define a procedure to monitor and limit discrepancies observed between synchronous time and universal co-ordinated time (i.e. UTC) in the SYNCHRONOUS AREA within each zone of synchronous operation of the UCTE. Reasonably it is applied during periods of uninterrupted interconnected operation, where the synchronous time is the same in all countries.

This policy section replaces the latest “UCTE technical rule for the correction of synchronous time” (dated 01.06.1998).

Criteria

C1. **Tolerated Range of Discrepancy**. A discrepancy between synchronous time and UTC time is tolerated within a range of ±20 seconds.

C2. **Target Range of Discrepancy**. The discrepancy between synchronous time and UTC time should be within a range of ±30 seconds under normal conditions in case of trouble-free operation of the interconnected network.

C3. **Exceptional Range of Discrepancy**. Under exceptional conditions the discrepancy between synchronous time and UTC time should be within a range of ±60 seconds under exceptional conditions in case of trouble-free operation of the interconnected network.

Requirements

R1. **Time Monitor**. Each UCTE SYNCHRONOUS AREA appoints a central instance (Time Monitor) that monitors continually the deviation between synchronous time (which is derived from the integration of the common SYSTEM FREQUENCY in this zone of synchronous operation) and the actual time (universal co-ordinated time, astronomical time).

R2. ***Communication***.

R3. **Frequency Set-Point for Secondary Control.** For time control purposes in the range of P1-D-C3 it is required that each CONTROL AREA (see P1-A) can involve a small displacement in the set-point frequency for SECONDARY CONTROL.

R4. **Frequency Set-Point for Units.** For time correction in the range of P1-D-C3 the set-point frequency of the units involved in PRIMARY CONTROL must not be changed.

Standards

S7. **Mean Frequency Value**. The mean value (as a result of PRIMARY CONTROL and SECONDARY CONTROL in co-operation) of the system frequency shall be the target frequency value of 50 Hz (see P1-A-C1).

S1. **Time Deviation Calculation**. The TIME DEVIATION between synchronous time and actual time is calculated for 8 a.m. each day. The relevant time zone is the Central European Time (CET = GMT+1) with daylight saving.

S2. **Time Correction Offset**. If the time deviation is within P1-D-C1, the offset for time correction is set to zero. If the deviation is out of P1-D-C1 and synchronous time is behind the actual time, the offset is set to +10 mHz. If the deviation is out of P1-D-C1 and synchronous time is ahead the actual time, the offset is set to –10 mHz.

S2.1. Exceptional Time Correction Offsets. Only under exceptional conditions out of P1-D-C3 offsets larger than 10 mHz (0.010 Hz) for the time correction of the synchronous time may be used. They are set by the time monitor.

S3. Time Correction Standard. The time correction offset is applied by one of the following values:

S3.1. Frequency set-point value. The frequency set-point value is calculated out of the sum of the nominal frequency 50 Hz and the frequency offset and valid for all hours of the next day, starting at 0 a.m., and is relevant for the operation of the SECONDARY CONTROL (P1-D-R3) and the calculation of performance criteria for SECONDARY CONTROL. All TSOs apply the transmitted frequency set-point value in their AGC system for the full next day.

S4. Time Correction Notice. The information for the time correction is forwarded towards all CONTROL AREAS of the SYNCHRONOUS AREA every day at 10 a.m. by the time monitor. The CONTROL AREAS themselves forward this information towards their sub-control areas without delay.

S4.1. Content of Notice. Each notice contains the time deviation, the time correction offset, the time correction procedure and the date and duration for the time correction.

S4.2. Notice Transmission. This notice is transmitted using secure and reliable electronic communication that allows a half-automated procedure.

S5. Time Correction Serialisation. Time deviations and notifications on time error corrections are serialised by the time monitor on a monthly basis.

Procedures

P1. UCTE time monitor. Under the normal condition of UCTE interconnection, the Laufenburg control centre (ETRANS) monitors continually the deviation between synchronous time and the actual time.

P2. Time correction notice. Under the normal condition of UCTE interconnection, the information is forwarded from Laufenburg (ETRANS) to the list of TSOs directly concerned (according to the "UCTE technical rule for the correction of synchronous time").

P3. Re-connection of asynchronous areas. Before re-connecting asynchronous areas of the UCTE network, the differences of time deviations between the different SYNCHRONOUS AREAS needs to be in target range. The smaller grid area being re-connected needs to limit this difference and to take over the synchronous time from the larger grid area once the re-connection is in operation.

P4. Outstanding notice. In case the TIME DEVIATION and correction notice is outstanding for a TSO, the TSO applies the nominal frequency 50 Hz (P1-A-C1) as frequency set-point value for SECONDARY CONTROL until it receives the outstanding notice.

E. Measures for Emergency Conditions

[UCPTE Rule 15: Measures for frequency control and precautions for the decrease of the frequency value, 1965]

[Appendix A1-G: Measures for Emergency Conditions]

[UCPTE Rule: Recommendations for the frequency in the interconnected operation of the UCPTE, 1996]

Introduction

EMERGENCY SITUATION in interconnected UCTE system occurs as a result of abnormal operation caused by dropping of generating power, outages or OVERLOADING of transmission lines that could not be covered by the operational reserve of affected TSO and cause imbalance of REAL POWER or REACTIVE POWER. The objective of this section is to specify the measures to be fulfilled to maintain operation of the interconnected UCTE network considering that when disruptions occur disturbances may be propagated over a vast area within a very short time[2].

SYSTEM FREQUENCY is the main criterion for observation of normal operation condition (see P1-A-C2). From the nature of the power-frequency characteristic (see P1-A-C4) of the large interconnected networks results that considerable frequency reduction caused by loss of generation capacity is more probable in small isolated systems than in whole UCTE parallel network.

Criteria

C1. **Operating conditions**. According the actual SYSTEM FREQUENCY the following operating conditions are defined:

- **C1.1.** **Normal operating condition**. If the deviation between the instantaneous frequency and the nominal set-point frequency 50 Hz (P1-A-C1) is equal or less than 50 mHz, operating conditions are considered as normal.
- **C1.2.** **Impaired operating condition**. If the deviation between the instantaneous frequency and the nominal set-point frequency is greater than 50 mHz but less than 150 mHz, operating conditions are deemed to be impaired, but with no major risk, provided that control facilities (controllers and reserves) in the affected areas are for sure ready for direct deployment.
- **C1.3.** **Severely impaired operating condition**. If the deviation between the instantaneous frequency and the nominal set-point frequency is greater than 150 mHz, operating conditions are deemed to be severely impaired, because there are significant risks of the malfunction of the interconnected network.

C2. **Load Shedding.** In case of a major frequency drop, automatic devices for LOAD SHEDDING in response to a frequency criterion must be installed at substations. In order to allow the support provided by interconnection to be enjoyed for as long as possible, the deliberate tripping of international interconnectors should be avoided, as long as interconnected operation remains possible.

Requirements

R1. **Emergency situation declaration.** Each partner has to describe characteristic of emergency situation in GRID CODE, or contracts with traders, generator owners and consumers. There must be clearly stated that emergency situation solving is question of highest priority at all.

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2 See policy 3 for further information on operational security.

R2. **Coordination**. NEIGHBORING TSO shall declare in bilateral operational agreements provisions for emergency assistance including provision to obtain emergency assistance from REMOTE SYSTEMS. All TSOs shall co-ordinate load shedding and action plans during emergency situations.

R3. **Accuracy of the frequency measurement for load shedding**. For load shedding must be maintained accuracy 5 to 10 mHz. In case that wide triggering band will not cause severe problems in system, accuracy 50 - 100 mHz is sufficient. This has to be observed and reviewed on case-by-case basis.

R4. **Tie lines equipment.** In order to maintain advantage and support of interconnection, international interconnectors must be equipped with single pole rapid reclosing devices and AUTOMATIC RECLOSING DEVICES for single phase fault.

R5. **Overload indication.** All international lines and large transformers must be equipped with devices that indicate overloads.

Standards

S1. **Maintaining of the synchronous operation.** In case of an emergency situation, the main task for all partners is to maintain the synchronous operation of the UCTE system. The TSO (in territory of which the emergency occurs, or that caused this situation) has to take immediately all possible measures to restore normal operation conditions, subject to the available means and resources at that time.

S2. **Notifying neighboring system.** TSO of the affected part of UCTE network has to inform the neighboring TSO on emergency situation and ask for cooperation.

S3. **Equipment of power plants.** Depending upon system characteristics (generating plant mix, network requirements, etc.) a sufficient number of generating sets must be equipped with devices for the isolation of units from the remainder of the system to maintain their own AUXILIARIES in case of NETWORK SEPARATION, thereby allowing the more rapid reconnection and resumption of load generation by these plants once network conditions allow. It should be avoided that the machines after disconnection from the network reach the emergency shut-off speed due to lost of load.

S4. **Coordination**. Measures relating to frequency, which are planned in the various TSO for disturbed operation, have to be coordinated.

Guidelines

G1. **In case of a general loss of voltage**, control centers, operating centers, substations, telecommunication systems and remote control systems must remain in operational condition, in order to allow the reconstitution of the network to be completed.

G2. **Increase of the frequency value above *50.2 Hz*.** Generation of active power has to be minimized, if the frequency is still high units should be disconnected from the system isolated operation supplying own AUXILIARIES.

G3. **Loss of a telecommunications link** or an instrumentation and control link between control centers, operating centers and production/transmission installations must not paralyze the operation of the interconnected network.

G4. **Severe frequency fall with/without separation of the UCTE network into partial networks**

As was stated above the most danger drop of frequency can occur after separation of synchronously operation UCTE system. In case of lack of power following action should be performed:

- immediately stop of the pump operation of the pump storage power plant
- set all running generation to the maximum power
- connect all possible quick start reserve

In case that this activation of generation is still not sufficient, in order to limit frequency reductions to the level at which power generation is still at all possible in those power stations remaining in the network activation of load shedding plans is necessary.

F. Performance Standards and Control Surveys

Introduction

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postponed

G. Technical Requirements and Qualifications for Generation

[Appendix A1-K: Technical Requirements and Qualifications for Generation]

[UCPTE Rule 34: Which demands does the grid operation has in regard to the characteristics of thermal generation?, 1983]

Introduction

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postponed