APPENDIX 1

LOAD-FREQUENCY CONTROL AND PERFORMANCE

A1 – Appendix 1: Load-Frequency Control and Performance [E]

Chapters

Introduction

This appendix to Policy 1 – Load-Frequency Control and Performance (⏩P1) explains and motivates the basic technical and organisational principles of LOAD-FREQUENCY CONTROL and other relevant control mechanisms for the UCTE, as it is applied in the SYNCHRONOUS AREA by the TSOs of the various CONTROL AREAS / BLOCKS. This appendix, organised as a collection of separate topics, shall be used as a covering paper for Policy 1.

Please refer to the introduction of the UCTE Operation Handbook (see ⏩I) for a general overview and to the glossary of terms of the UCTE Operation Handbook (see ⏩G) for detailed definitions of terms used within this appendix.

History of Changes

v1.9 draft 16.06.2004 OpHB-Team update after consultation period

v1.8 draft 01.03.2004 OpHB-Team minor changes

Current Status

This document summarises technical descriptions and backgrounds of a subset of current UCTE rules and recommendations related to generation control and performance issues, with additional items.

This appendix replaces previous UCTE ground rules and recommendations regarding PRIMARY and SECONDARY frequency and active POWER CONTROL, regulation reserves and correction of SYNCHRONOUS TIME. This version of the document (version 1.9, level E, dated 16.06.2004) has "final" status.

A. Primary Control

[UCTE Operation Handbook Policy 1 Chapter A: Primary Control, 2004]

[UCTE-Ground Rule for the co-ordination of the accounting and the organisation of the load-frequency control, 1999]

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

[UCPTE Rule 31: Control characteristics of the UCPTE interconnected grid, 1982]

[UCTE-Ground Rules – Supervision of the application of rules concerning primary and secondary control of frequency and active power in the UCTE, 1999]

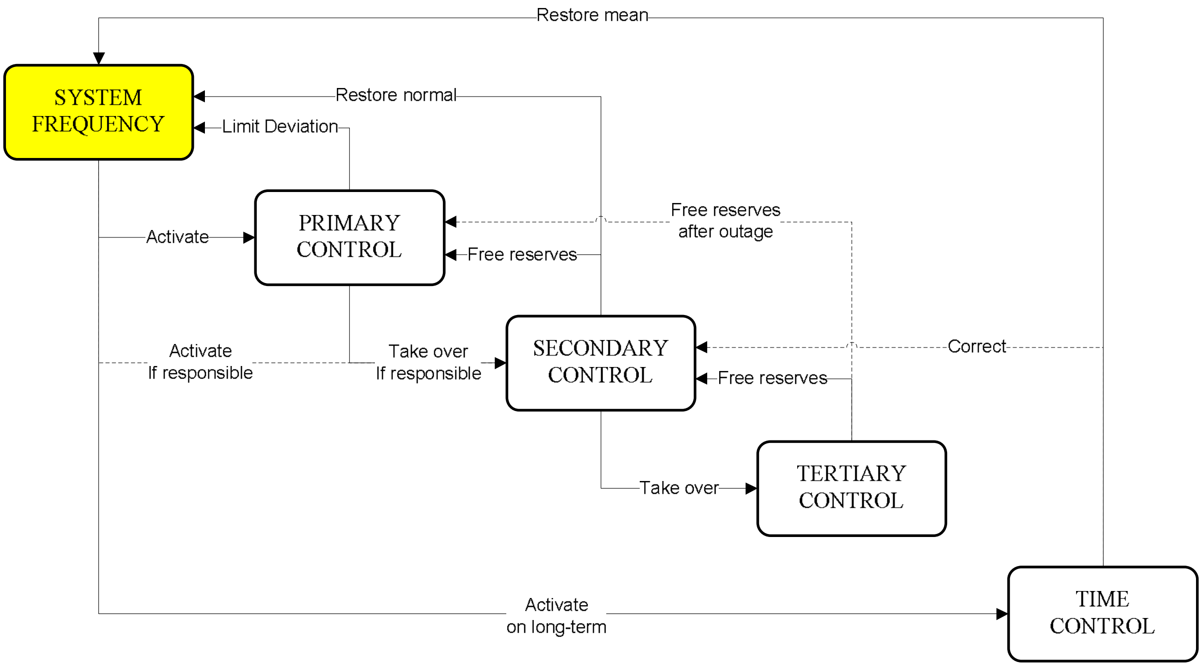
1. Power Equilibrium

In any electric system, the ACTIVE POWER has to be generated at the same time as it is consumed. Power generated must be maintained in constant equilibrium with power consumed / demanded, otherwise a POWER DEVIATION occurs. Disturbances in this balance, causing a deviation of the SYSTEM FREQUENCY from its set-point values, will be offset initially by the kinetic energy of the rotating generating sets and motors connected.

There is only very limited possibility of storing electric energy as such. It has to be stored as a reservoir (coal, oil, water) for large power systems, and as chemical energy (battery packs) for small systems. This is insufficient for controlling the power equilibrium in real-time, so that the production system must have sufficient flexibility in changing its generation level. It must be able instantly to handle both changes in demand and outages in generation and transmission, which preferably should not become noticeable to network users.

2. System Frequency

The electric frequency in the network (the SYSTEM FREQUENCY *f*) is a measure for the rotation speed of the synchronised generators. By increase in the total DEMAND the SYSTEM FREQUENCY (speed of generators) will decrease, and by decrease in the DEMAND the SYSTEM FREQUENCY will increase. Regulating units will then perform automatic PRIMARY CONTROL action and the balance between demand and generation will be re-established. The FREQUENCY DEVIATION is influenced by both the total inertia in the system, and the speed of PRIMARY CONTROL. Under undisturbed conditions, the SYSTEM FREQUENCY must be maintained within strict limits in order to ensure the full and rapid deployment of control facilities in response to a disturbance. Out of periods for the correction of SYNCHRONOUS TIME, the set-point frequency is 50 Hz.



Even in case of a major FREQUENCY DEVIATION / OFFSET, each CONTROL AREA / BLOCK will maintain its interconnections with ADJOINING CONTROL AREAS, provided that the secure operation of its own system is not jeopardised.

3. Droop of a Generator

The DROOP OF A GENERATOR s_G is a ratio (without dimension) and is generally expressed as a percentage:

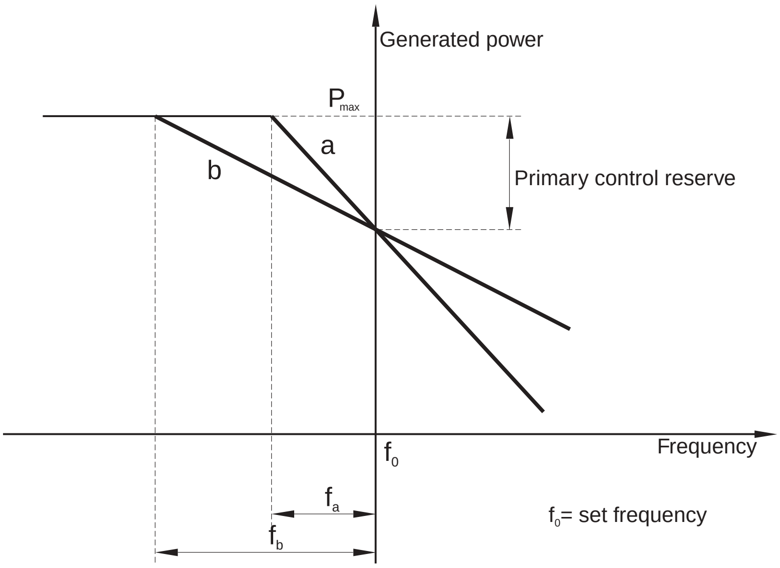
$$s_G = \frac{-\Delta f / f_n}{\Delta P_G / P_{Gn}} \text{ in \%}$$

The variation in SYSTEM FREQUENCY is defined as follows, with f_n being the rated frequency:

$$\Delta f = f - f_n$$

The relative variation in power output is defined as the quotient of the variation in power output ΔP_G of a generator (in steady-state operation, provided that the PRIMARY CONTROL RANGE is not completely used up) and its rated active power output P_{Gn}.

The contribution of a generator to the correction of a disturbance on the network depends mainly upon the DROOP OF THE GENERATOR and the PRIMARY CONTROL RESERVE of the generator concerned. The following figure shows a diagram of variations in the generating output of two generators *a* and *b* of different droop under equilibrium conditions, but with identical PRIMARY CONTROL RESERVES.



In case of a minor disturbance (FREQUENCY OFFSET < Δf_b), the contribution of generator *a* (which has the controller with the smaller droop) to the correction of the disturbance will be greater than that of generator *b*, which has the controller with the greater droop. The FREQUENCY OFFSET (Δf_a) at which the PRIMARY CONTROL RESERVE of generator a will be exhausted (i.e. where the power generating output reaches its maximum value P_{max}) will be smaller than that of generator b (Δf_b), even where both generators have identical PRIMARY CONTROL RESERVES.

In case of a major disturbance (frequency offset > Δf_b), the contributions of both generators to PRIMARY CONTROL under quasi-steady-state conditions will be equal.

4. Network Power Frequency Characteristic

The NETWORK POWER FREQUENCY CHARACTERISTIC of a SYNCHRONOUS AREA / BLOCK is the quotient of the POWER DEVIATION ΔP_a responsible for the disturbance and the quasi-steady-state FREQUENCY DEVIATION Δf caused by the disturbance (power deficits are considered as negative values):

$$\lambda_u = \frac{\Delta P_a}{\Delta f} \text{ in MW/Hz}$$

The NETWORK POWER FREQUENCY CHARACTERISTIC λ_i is measured for a given CONTROL AREA / BLOCK *i*. This corresponds to the quotient of ΔP_i (the POWER DEVIATION measured at the TIE-LINES of the CONTROL AREA / BLOCK *i*) and the FREQUENCY DEVIATION Δf in response to the disturbance (in the CONTROL AREA / BLOCK where the disturbance originates, it will be necessary to add the power surplus, or subtract the power deficit, responsible for the disturbance concerned).

$$\lambda_i = \frac{-\Delta P_i}{\Delta f} \text{ in MW/Hz}$$

The contribution of each CONTROL AREA / BLOCK to the NETWORK POWER FREQUENCY CHARACTERISTIC is based upon the set point value λ_{io} for the NETWORK POWER FREQUENCY CHARACTERISTIC in the CONTROL AREA / BLOCK concerned. This set-point value is obtained by the multiplication of the set-point NETWORK POWER FREQUENCY CHARACTERISTIC λ_{uo} for the entire SYNCHRONOUS AREA and the contribution coefficients C_i of the various CONTROL AREAS / BLOCKS:

$$\lambda_{io} = C_i \lambda_{uo}$$

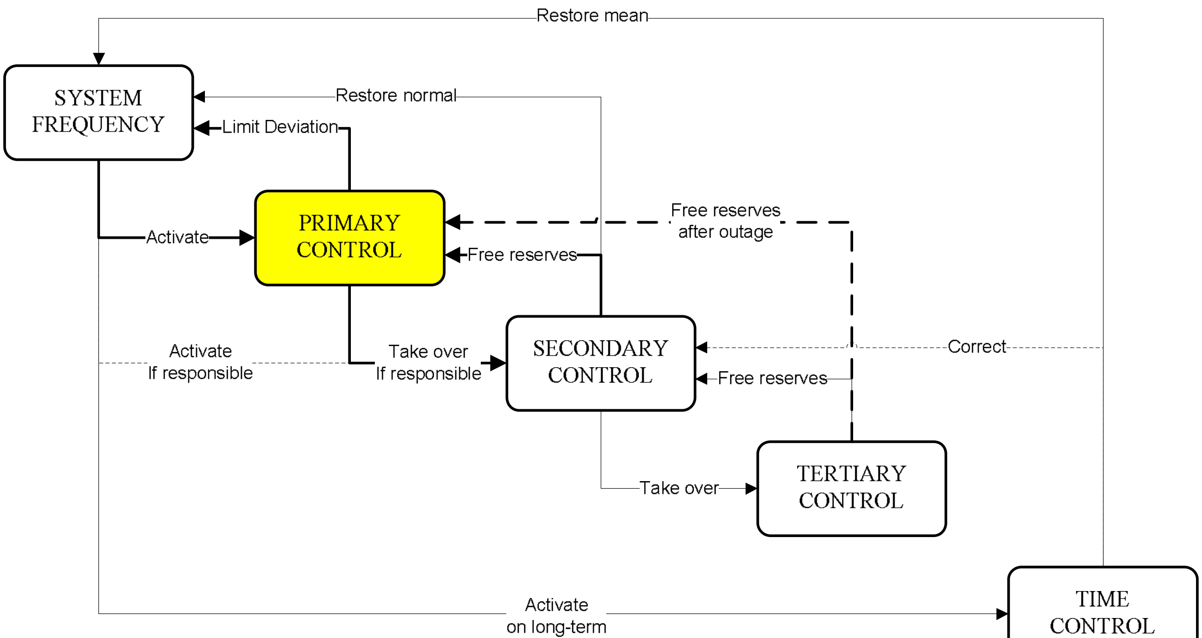
This formula is used to determine the requested contribution C_i of a CONTROL AREA / BLOCK to PRIMARY CONTROL.

The NETWORK POWER FREQUENCY CHARACTERISTIC of a given CONTROL AREA / BLOCK should remain as constant as possible, within the frequency range applied. This being so, the insensitivity range of controllers should be as small as possible, and in any case should not exceed ±10mHz. Where dead bands exist in specific controllers, these must be offset within the CONTROL AREA / BLOCK concerned.

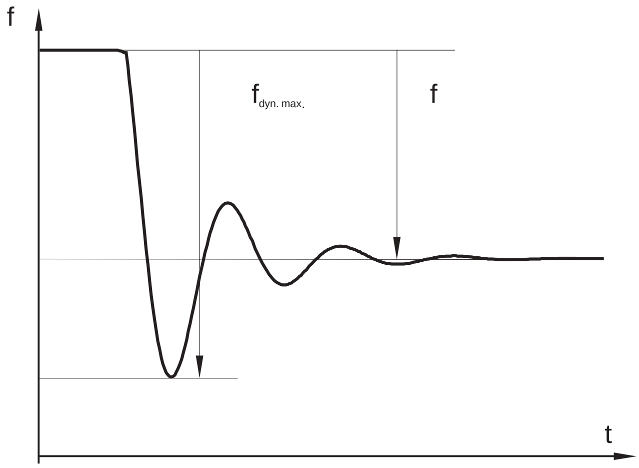
The set-point value λ_{uo} for the overall NETWORK POWER FREQUENCY CHARACTERISTIC is defined by the UCTE on the basis of the conditions described in the policy, taking account of measurements, experience and theoretical considerations.

5. *Primary Control Basics*

Various disturbances or random deviations which impair the equilibrium of generation and demand will cause a FREQUENCY DEVIATION, to which the PRIMARY CONTROLLER of generating sets involved in PRIMARY CONTROL will react at any time.



The proportionality of PRIMARY CONTROL and the collective involvement of all interconnection partners is such that the equilibrium between power generated and power consumed will be immediately restored, thereby ensuring that the SYSTEM FREQUENCY is maintained within permissible limits. In case that the frequency exceeds the permissible limits, additional measures out of the scope of PRIMARY CONTROL, such as (automatic) LOAD-SHEDDING, are required and carried out in order to maintain interconnected operation.



$f_{dyn.\ max.}$ = Dynamic frequency deviation
f = Quasi-steady-state deviation

This deviation in the SYSTEM FREQUENCY will cause the PRIMARY CONTROLLERS of all generators subject to PRIMARY CONTROL to respond within a few seconds. The controllers alter the power delivered by the generators until a balance between power output and consumption is re-established. As soon as the balance is re-established, the SYSTEM FREQUENCY stabilises and remains at a quasi-steady-state value, but differs from the frequency set-point because of the DROOP OF THE GENERATORS which provide proportional type of action. Consequently, power cross-border exchanges in the interconnected system will differ from values agreed between companies. SECONDARY CONTROL (see ⏩A1-B) will take over the remaining FREQUENCY and POWER DEVIATION after 15 to 30 seconds. The function of SECONDARY CONTROL is to restore power cross-border exchanges to their (programmed) set-point values and to restore the SYSTEM FREQUENCY to its set-point value at the same time.

The magnitude $\Delta f_{dyn.max}$ of the dynamic FREQUENCY DEVIATION is governed mainly by the following:

- the amplitude and development over time of the disturbance affecting the balance between power output and consumption;
- the kinetic energy of rotating machines in the system;
- the number of generators subject to PRIMARY CONTROL, the PRIMARY CONTROL RESERVE and its distribution between these generators;
- the dynamic characteristics of the machines (including controllers);
- the dynamic characteristics of loads, particularly the self-regulating effect of loads.

The quasi-steady-state FREQUENCY DEVIATION Δf is governed by the amplitude of the disturbance and the NETWORK POWER FREQUENCY CHARACTERISTIC, which is influenced mainly by the following:

- the droop of all generators subject to PRIMARY CONTROL in the SYNCHRONOUS AREA;
- the sensitivity of consumption to variations in SYSTEM FREQUENCY.

6. Principle of Joint Action

Each TRANSMISSION SYSTEM OPERATOR (TSO) must contribute to the correction of a disturbance in accordance with its respective contribution coefficient to PRIMARY CONTROL. These contribution coefficients C_i are calculated on a regular basis for each CONTROL AREA / BLOCK or interconnection partner / TSO using the following formula:

$$C_i = \frac{E_i}{E_u}$$

with

E_i being the electricity generated in CONTROL AREA / BLOCK *i* (including electricity production for export and scheduled electricity production from jointly operated units) and

E_u being the total (sum of) electricity production in all *N* CONTROL AREAS / BLOCKS of the SYNCHRONOUS AREA.

In order to ensure that the principle of joint action is observed, the NETWORK POWER FREQUENCY CHARACTERISTICS of the various CONTROL AREAS should remain as constant as possible. This applies particularly to small FREQUENCY DEVIATIONS Δf, where the "dead bands" of generators may have an unacceptable influence upon the supply of PRIMARY CONTROL energy in the CONTROL AREAS concerned.

7. Target Performance

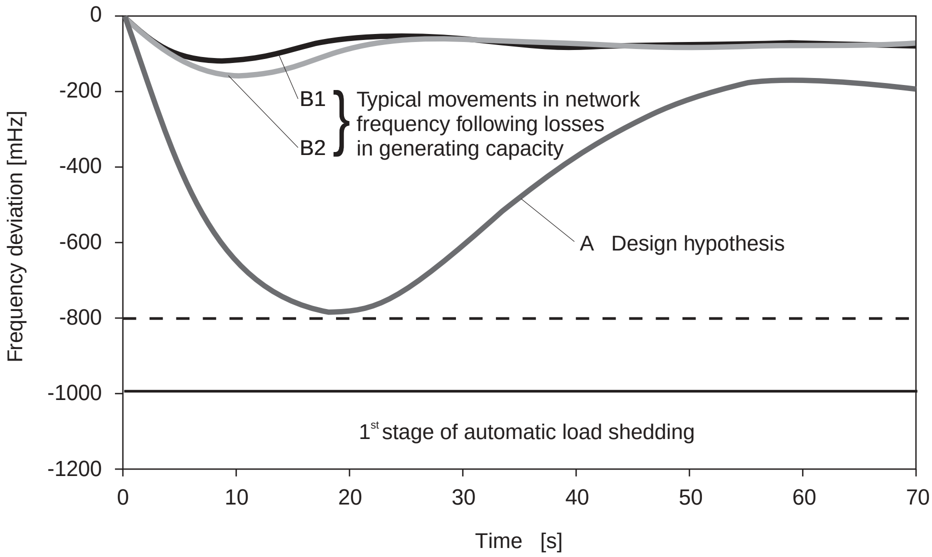
Defining conditions for the target efficiency of PRIMARY CONTROL are based upon the following parameters:

- the simultaneous loss of two power plant units, or the loss of a line section or busbar;
- experience has shown that incidents leading to an even greater loss of power are extremely rare;
- the control of such incidents by the activation of far greater control power than is necessary may lead to the overloading of the transmission system, thereby jeopardising the interconnected network.

The design hypothesis applied is based upon unfavourable parameters which provide a margin of safety in estimated values. Consequently, it is probable that even more serious incidents could be accommodated in practice without the need for LOAD-SHEDDING. Based on the parameters above, the reference incident was defined to be 3000 MW for the entire SYNCHRONOUS AREA (see ⏩P1-A-C3).

Starting from undisturbed operation of the interconnected network, a sudden loss of 3000 MW generating capacity must be offset by PRIMARY CONTROL alone, without the need for customer LOAD-SHEDDING in response to a FREQUENCY DEVIATION. In addition, where the self-regulating effect of the system load is assumed according to be 1 %/Hz, the absolute FREQUENCY DEVIATION must not exceed 180 mHz. Likewise, sudden load-shedding of 3000 MW in total must not lead to a FREQUENCY DEVIATION exceeding 180 mHz. Where the self-regulating effect of the load is not taken into account, the absolute FREQUENCY DEVIATION must not exceed 200 mHz.

The following figure shows movements in the SYSTEM FREQUENCY for a given design hypothesis (case A), where dynamic requirements for the activation of control power are fulfilled in accordance with the requirements for deployment time. Unfavourable assumptions have been selected for all model parameters. The maximum absolute FREQUENCY DEVIATION is 800 mHz - this means that the threshold for LOAD-SHEDDING will not be reached by some margin.



A Loss in generating capacity: P = 3000 MW, $P_{network}$ = 150 GW, self-regulating effect of load: 1% / Hz
B1 Loss in generating capacity: P = 1300 MW, $P_{network}$ = 200 GW, self-regulating effect of load: 2 % / Hz
B2 Loss in generating capacity: P = 1300 MW, $P_{network}$ = 200 GW, self-regulating effect of load: 1% / Hz

For comparative purposes, simulations have also been undertaken using realistic model parameters (case B), in order to allow the typical FREQUENCY DEVIATION associated with customary losses in generating capacity to be plotted in parallel. These simulations show that, for a loss of capacity up to 1300 MW, the absolute FREQUENCY DEVIATION will remain below 200 mHz.

If the target performance described above is to be achieved, the system must be operated in such a way, depending upon the system load, that the NETWORK POWER FREQUENCY CHARACTERISTIC for the entire SYNCHRONOUS AREA falls within a relatively narrow band. Taking account of the self-regulating effect of load, this gives the following table:

Self-regulating effect	Network power	Network power frequency characteristic
1 %/Hz	150 GW	16500 MW/Hz
1 %/Hz	300 GW	18000 MW/Hz
2 %/Hz	150 GW	18000 MW/Hz
2 %/Hz	300 GW	21000 MW/Hz

The following assumptions have been applied for the definition of marginal conditions for the operation of PRIMARY CONTROL[1]:

- Design basis / reference incident: Sudden deviation of 3000 MW in the balance of production and consumption; system off-peak load about 150 GW and peak load about 300 GW
- System start time constant: 10 to 12 seconds
- Self-regulating effect of load: 1 %/Hz
- Maximum permissible FREQUENCY DEVIATION quasi-steady-state: ±180 mHz and dynamic: ±800 mHz

The maximum dynamic FREQUENCY DEVIATION of ±800 mHz includes a safety margin. This margin of 200 mHz in total is intended to cover the following influences and elements of uncertainty:

- Possible stationary FREQUENCY DEVIATION before an incident (50 mHz)
- Insensitivity of turbine controller (20 mHz)
- Larger dynamic FREQUENCY DEVIATION at the site of the incident, not taken into account in the specific network model used for simulations (50 mHz)

1: The value of 3000 MW used here as the reference incident depends on the size of the SYNCHRONOUS AREA and is subject to change in case of extension of the SYNCHRONOUS AREA (or disconnection of an area).

- Other elements of uncertainty in the model (approximately 10 %, 80 mHz)

In case of LOAD-SHEDDING, accuracy of 50 to 100 mHz will generally suffice for relay trip thresholds.

8. Primary Control Reserve

The total PRIMARY CONTROL RESERVE for the entire SYNCHRONOUS AREA P_{pu} is determined by the UCTE on the basis of the conditions set out in the previous subsections, taking account of measurements, experience and theoretical considerations.

The shares P_{pi} of the CONTROL AREAS / BLOCKS are defined by multiplying the calculated reserve for the SYNCHRONOUS AREA and the contribution coefficients C_i of the various CONTROL AREAS / BLOCKS:

$$P_{pi} = P_{pu} C_i$$

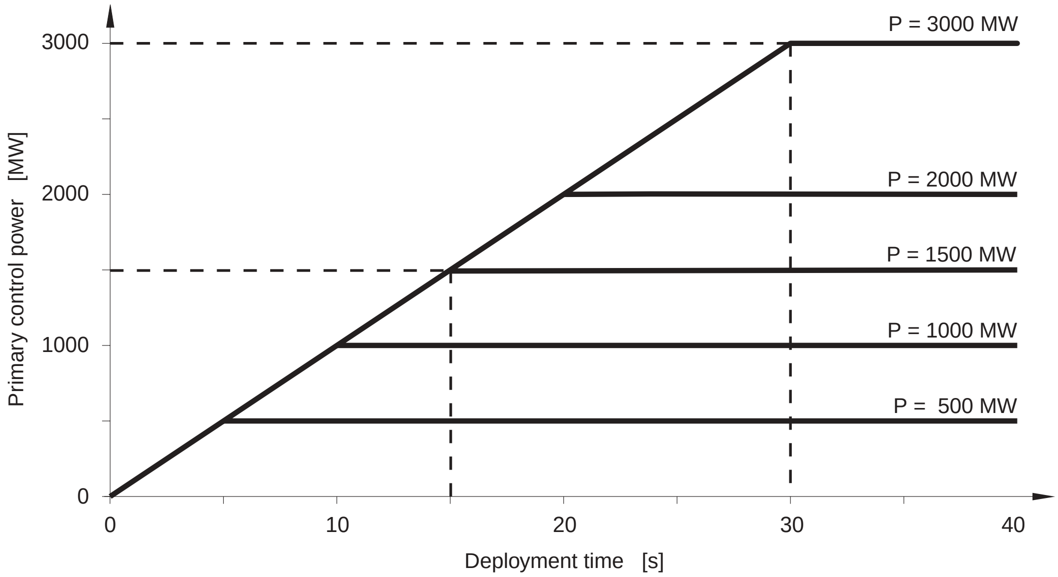
The entire PRIMARY CONTROL RESERVE is activated in response to a quasi-steady-state FREQUENCY DEVIATION of –200 mHz or more. Likewise, in response to a FREQUENCY DEVIATION of +200 mHz or more, power generation must be reduced by the value of the entire PRIMARY CONTROL RESERVE.

In order to restrict the calling up of the PRIMARY CONTROL RESERVE to unscheduled power unbalances, the SYSTEM FREQUENCY should not exceed or fall below a range of ±20 mHz for long periods under undisturbed conditions.

9. Deployment Time of Primary Control Reserve

The deployment time of the PRIMARY CONTROL RESERVES of the various CONTROL AREAS / BLOCKS should be as similar as possible, in order to minimise dynamic interaction between CONTROL AREAS / BLOCKS. In this instance, we are concerned with anticipated performance, rather than with the logic of controllers.

For the following, a reference incident of 3000 MW (loss of generation or load, see ⏩P1-A-C3) for the SYNCHRONOUS AREA is considered. The PRIMARY CONTROL RESERVE of each CONTROL AREA / BLOCK (determined in accordance with the corresponding contribution coefficient) must be fully activated within 15 seconds in response to disturbances ΔP of less than 1500 MW (it has been assumed that, where values for reserve power to be activated are smaller, deployment times of less than 15 seconds will be difficult to achieve), or within a linear time limit of 15 to 30 seconds in response to a ΔP of 1500 to 3000 MW. As a minimum requirement, the deployment time of the PRIMARY CONTROL RESERVE must be consistent with the curves plotted in the following figure, which represent the overall behaviour of the system. The activated power will lie on or above the plotted curves, until the balance between power generation and consumption has been restored. For each CONTROL AREA / BLOCK, the figures for power indicated are multiplied by the relevant contribution coefficient C_i. The following figure illustrates the minimum deployment of PRIMARY CONTROL POWER as a function of time and the size of the disturbance ΔP.



10.Performance Measurement

A distinction is drawn between the quality of control in the entire SYNCHRONOUS AREA (overall quality) and the quality of control in each CONTROL AREA / BLOCK (local quality). Each interconnected undertaking / TSO must act to provide effective PRIMARY CONTROL, in order to ensure that a high overall level of quality is maintained.

The main purpose of an overall quality check is to evaluate the performance of the PRIMARY CONTROL of the entire SYNCHRONOUS AREA. This evaluation is carried out by analysing the SYSTEM FREQUENCY of the network during disturbances. The main purpose of this frequency analysis is to estimate the operational reliability of the interconnected network.

The NETWORK POWER FREQUENCY CHARACTERISTIC λ_u of the entire SYNCHRONOUS AREA is calculated by the following relationship:

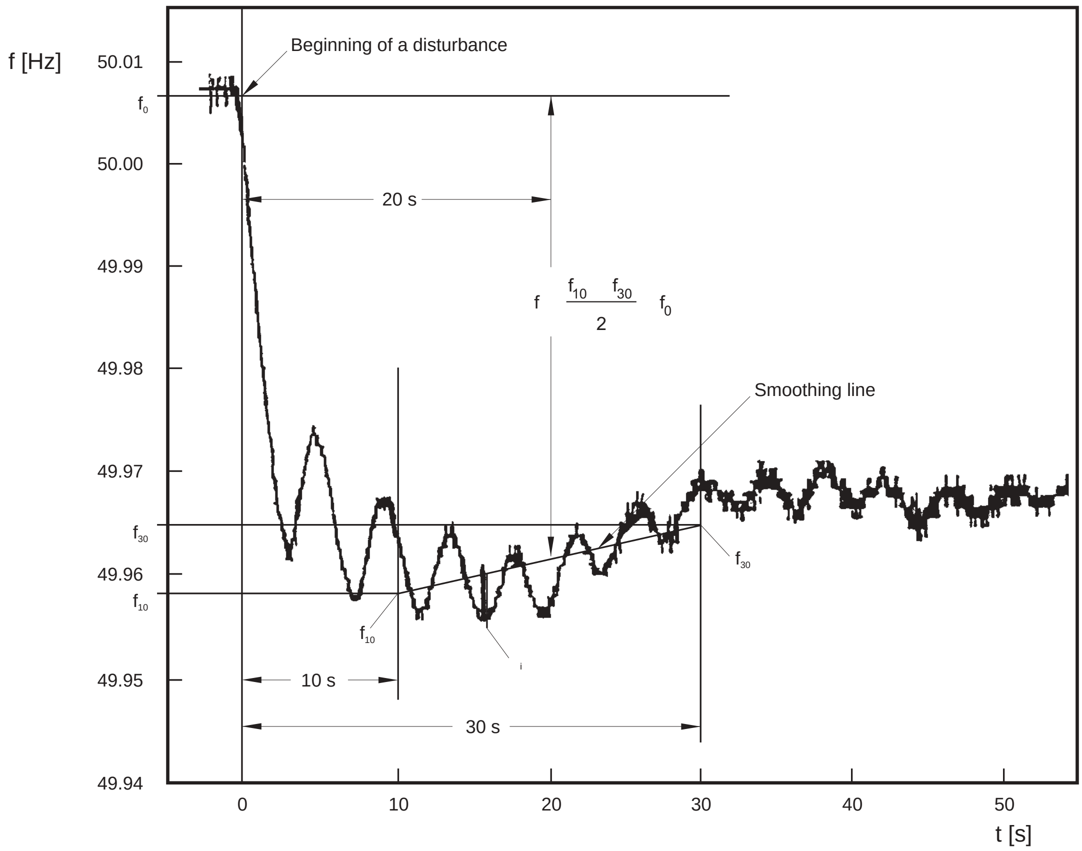
$$\lambda_u = \frac{\Delta P_a}{\Delta f}$$

with

ΔP_a being the variation in power causing a disturbance and

Δf being the quasi-steady-state FREQUENCY DEVIATION in response to a disturbance.

This is determined from a "smoothing line" drawn between 10 and 30 seconds after the disturbance, such that the sum of the FREQUENCY DEVIATIONS ε_i in respect of this line is zero (the line must be drawn so that the sum of the absolute deviations ε is a minimum, see next figure).



It is assumed that the main part of the PRIMARY CONTROL RESERVE is activated after 20 seconds, while the contribution of SECONDARY CONTROL to the correction of the disturbance will not yet be perceptible.

A local quality check will allow each party to ascertain whether their respective contribution to PRIMARY CONTROL is consistent with the requirements.

An interconnected undertaking / TSO can check the quality of its PRIMARY CONTROL by evaluating the NETWORK POWER FREQUENCY CHARACTERISTIC in its CONTROL AREA / BLOCK each time a disturbance occurs, and comparing it with the NETWORK POWER FREQUENCY CHARACTERISTIC of the entire SYNCHRONOUS AREA.

The NETWORK POWER FREQUENCY CHARACTERISTIC λ_i in a CONTROL AREA / BLOCK is calculated by the following relationship:

$$\lambda_i = \frac{-\Delta P_i}{\Delta f}$$

with

> ΔP_i being the variation in power generated in a CONTROL AREA / BLOCK in response to a disturbance, measured at interconnecting points / TIE-LINES (in the CONTROL AREA / BLOCK where the disturbance occurs, the power deficit/surplus must be added/subtracted) and
>
> Δf being the quasi-steady-state FREQUENCY DEVIATION in response to a disturbance of ΔP_a.

These two measurements must be simultaneous (the time stamps of all measurements need to be synchronous). It must be possible to estimate measurement errors.

In CONTROL AREAS / BLOCKS, where fast random changes in total cross-border exchange power are comparable with variations in the cross-border exchange power for the area ΔP_i, the latter may be determined from smoothing lines representing the cross-border exchange power before and after a disturbance.

In order to allow the quality of control to be monitored, it is advisable to record and continuously analyse outages in production or consumption exceeding 1000 MW[2]. The following information is required for this purpose:

- the location of the disturbance,
- date and time of the disturbance,
- the amount of production/consumption lost during the disturbance,
- the type of the disturbance.

The affected interconnected undertaking / TSO will make this information available to all other interconnection partners / TSOs.

Even if the SYSTEM FREQUENCY measurement and power cross-border exchange measurements taken during a disturbance are inaccurate, they will allow each interconnected undertaking / TSO to carry out a statistical analysis of the NETWORK POWER FREQUENCY CHARACTERISTICS and PRIMARY CONTROL POWER being activated, and to compare the results of this analysis with corresponding values for the entire SYNCHRONOUS AREA.

Each interconnected undertaking / TSO needs to complete regular checks in order to ensure that deployment times for their PRIMARY CONTROL RESERVE are consistent with the requirements of PRIMARY CONTROL.

[2]: The value depends on the size of the SYNCHRONOUS AREA, the value of 1000 MW holds for the first SYNCHRONOUS AREA of 2004 only, for the second SYNCHRONOUS AREA of 2004 the value is 250 MW instead.

B. Secondary Control

[UCTE Operation Handbook Policy 1 Chapter B: Secondary Control, 2004]

[UCPTE Rule 18: Terminology of interconnected operation, 1968]

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

[UCPTE Rule 1: The practical application of load-frequency control in western Europe, 1955]

[UCPTE Rule 24: Control equipment for load-frequency control, 1971]

[UCPTE Rule 26: General aspects about the registration and the balance of unintended deviation in the interconnected grid, 1974]

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

1. Introduction

Any imbalance between electric power generation and consumption will result (in real-time) in a frequency change within the complete network of the SYNCHRONOUS AREA. As a result over time, a FREQUENCY DEVIATION occurs. At SYSTEM FREQUENCIES below 50 Hz, the total DEMAND has been larger than the total generation, at frequencies above 50 Hz the total DEMAND has been less than the total generation. In practise, the DEMAND varies continuously, even without having forecast errors, so that SECONDARY CONTROL on a real-time basis is required on a continuous basis. A deviation Δf of SYSTEM FREQUENCY from its set-point value of 50 Hz will activate PRIMARY CONTROL power throughout the SYNCHRONOUS AREA:

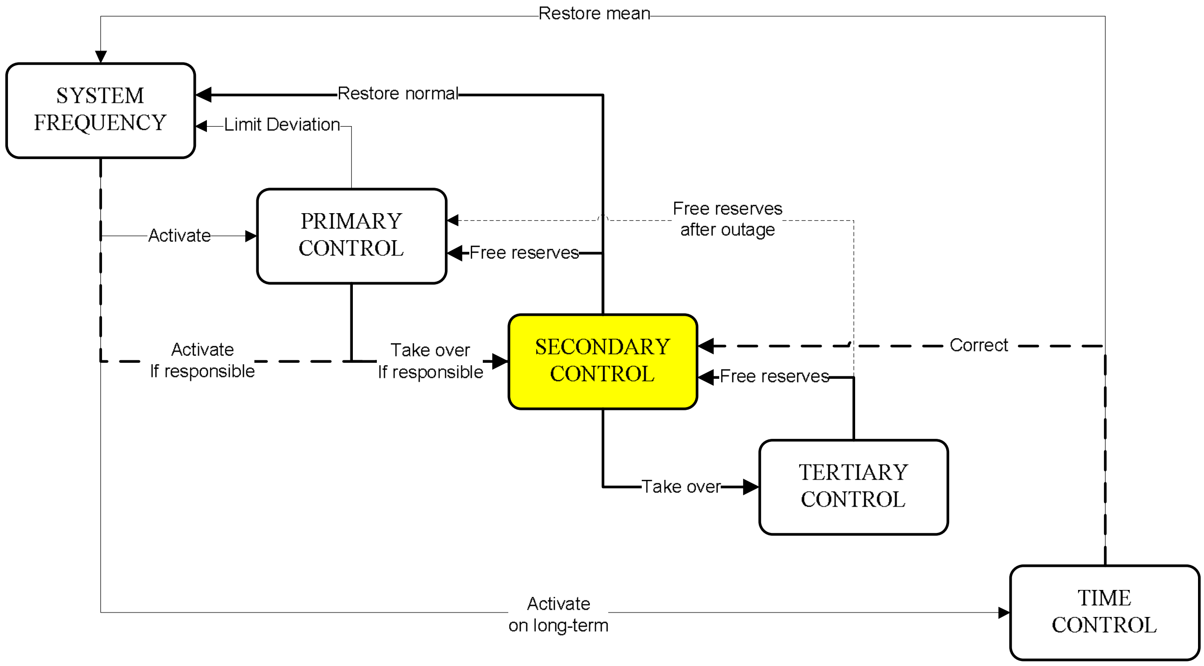
$$\Delta P_u = \lambda_u \bullet \Delta f$$

with

λ_u = the POWER SYSTEM FREQUENCY CHARACTERISTIC of the whole SYNCHRONOUS AREA, i.e. the sum of the POWER SYSTEM FREQUENCY CHARACTERISTICS of all CONTROL AREAS / BLOCKS.

PRIMARY CONTROL (see ⏩A1-A) allows a balance to be re-established at a SYSTEM FREQUENCY other than the frequency set-point value (at a quasi-steady-state FREQUENCY DEVIATION Δf), in response to a sudden imbalance between power generation and consumption (incident) or random deviations from the power equilibrium. Since all CONTROL AREAS / BLOCKS contribute to the control process in the interconnected system, with associated changes in the balance of generation and consumption in these CONTROL AREAS, an imbalance between power generation and consumption in any CONTROL AREA will cause power interchanges between individual CONTROL AREAS to deviate from the agreed / scheduled values (power interchange deviations ΔP_i).

The function of SECONDARY CONTROL (also known as load-frequency control or frequency-power-control, see ⏩A1-B) is to keep or to restore the power balance in each CONTROL AREA / BLOCK and, consequently, to keep or to restore the SYSTEM FREQUENCY f to its set-point value of 50 Hz and the power interchanges with ADJACENT CONTROL AREAS to their programmed scheduled values, thus ensuring that the full reserve of PRIMARY CONTROL POWER activated will be made available again. In addition, SECONDARY CONTROL may not impair the action of the PRIMARY CONTROL. These actions of SECONDARY CONTROL will take place simultaneously and continually, both in response to minor deviations (which will inevitably occur in the course of normal operation) and in response to a major discrepancy between production and consumption (associated e.g. with the tripping of a generating unit or network disconnection). In order to fulfil these requirements in parallel, SECONDARY CONTROL needs to be operated by the NETWORK CHARACTERISTIC METHOD (see ⏩A1-B-2).



Whereas all CONTROL AREAS provide mutual support by the supply of PRIMARY CONTROL POWER during the PRIMARY CONTROL process, only the CONTROL AREA / BLOCK affected by a power unbalance is required to undertake SECONDARY CONTROL action for the correction. Consequently, only the controller of the CONTROL AREA / BLOCK, in which the imbalance between generation and consumption has occurred, will activate the corresponding SECONDARY CONTROL POWER within its CONTROL AREA / BLOCK. Parameters for the SECONDARY CONTROLLERS of all CONTROL AREAS need to be set such that, ideally, only the controller in the zone affected by the disturbance concerned will respond and initiate the deployment of the requisite SECONDARY CONTROL POWER.

Within a given CONTROL AREA / BLOCK, the DEMAND should be covered at all times by electricity produced in that area, together with electricity imports (under purchase contracts and/or electricity production from jointly operated plants outside the zone concerned). In order to maintain this balance, generation capacity for use as SECONDARY CONTROL RESERVE must be available to cover power plant outages and any disturbances affecting production, consumption and transmission. SECONDARY CONTROL is applied to selected generator sets in the power plants comprising the control loop.

SECONDARY CONTROL operates for periods of several minutes, and is therefore timely dissociated from PRIMARY CONTROL. This behaviour over time is associated with the PI (proportional-integral) characteristic of the SECONDARY CONTROLLER. SECONDARY CONTROL makes use of measurements of the SYSTEM FREQUENCY and ACTIVE POWER flows on the TIE-LINES of the CONTROL AREA / BLOCK, a SECONDARY CONTROLLER, that computes power set-point values of selected generation sets for control (see ⏩A1-B-4), and the transmission of these set-point values to the respective generation sets.

When consumption exceeds production on a continuous basis, immediate action must be taken to restore the balance between the two (by the use of standby supplies, contractual load variation or LOAD-SHEDDING or the shedding of a proportion of customer load as a last resort). Sufficient transmission capacity must be maintained at all times to accommodate reserve control capacity and standby supplies.

Since it is technically impossible to guard against all random variables affecting production, consumption or transmission, the volume of reserve capacity will depend upon the level of risk which is deemed acceptable. These principles will apply, regardless of the division of responsibilities between the parties involved in the supply of electricity to consumers.

2. Principle of the Network Characteristic Method

In order to determine, whether power INTERCHANGE DEVIATIONS are associated with an imbalance in the CONTROL AREA / BLOCK concerned or with the activation of PRIMARY CONTROL POWER, the NETWORK CHARACTERISTIC METHOD needs to be applied for SECONDARY CONTROL of all CONTROL AREAS / BLOCKS in the SYNCHRONOUS AREA.

According to this method, each CONTROL AREA / BLOCK is equipped with one SECONDARY CONTROLLER to minimise the AREA CONTROL ERROR (ACE) G in real-time:

$$G = P_{meas} - P_{prog} + K_{ri}\left(f_{meas} - f_0\right)$$

with

P_{meas} being the sum of the instantaneous measured active power transfers on the tie-lines,

P_{prog} being the resulting exchange program with all the neighbouring / ADJACENT CONTROL AREAS,

K_{ri} being the K-FACTOR of the CONTROL AREA, a constant (MW/Hz) set on the SECONDARY CONTROLLER, and

f_{means}-f_0 being the difference between the instantaneous measured SYSTEM FREQUENCY and the set-point frequency.

The ACE is the CONTROL AREA's unbalance P_{meas}-P_{prog} minus its contribution to the PRIMARY CONTROL, if K_{ri} is equal to the CONTROL AREA's POWER SYSTEM FREQUENCY CHARACTERISTIC. The power transits are considered positive for export and negative for import (see ⏩I-J). Hence, a positive (respectively a negative) ACE requires a reduction (resp. an increase) of the SECONDARY CONTROL POWER.

The ACE must be kept close to zero in each CONTROL AREA / BLOCK. The purpose is twofold:

- **Control area / block balance**. If the measured SYSTEM FREQUENCY f_{meas} is equal to the set-point frequency f_0, the ACE is the unbalance of the CONTROL AREA / BLOCK, i.e. the difference between the measured power exchanges P_{meas} and the scheduled exchanges P_{sched}.
- **Non detrimental effect on primary control**. The power developed by PRIMARY CONTROL in the CONTROL AREA / BLOCK under consideration is given by $-\lambda_i\,(f_{meas} - f_0)$. This amount of power has to be subtracted from the power unbalance in order not to neutralise the PRIMARY CONTROL action. This is true if K_{ri}=λ_i. Due to the uncertainty on the self regulating effect of the load, K_{ri} may be chosen slightly higher than λ_i such that the SECONDARY CONTROL will accentuate the effect of the PRIMARY CONTROL and not counteract it.

When $\Delta f = f_{means} - f_0 = 0$, under balanced conditions ($P_{meas} = P_{prog}$), the ACE will also be equal to zero.

For reasons of simplicity, the NETWORK CHARACTERISTIC METHOD will be explained on the basis of an interconnected system comprising of two CONTROL AREAS only.

a) Before a disturbance:

The situation before the disturbance is assumed to be the following:

$\Delta f = 0$ (actual frequency f = set point frequency f_o)

$\Delta P_{12} = 0$ (actual exchange capacity = set point exchange capacity)

b) Disturbance and PRIMARY CONTROL:

Let us suppose that, in network 2, a generated power P_a is lost. PRIMARY CONTROL stabilises the frequency at f_o+Δf . The following relationship will apply to the entire system: $\Delta f = P_a/\lambda_u$, where λ_u is the NETWORK POWER FREQUENCY CHARACTERISTIC. Since generating capacity is lost, P_a will have a negative value. Hence, Δf will also be negative.

In response to the FREQUENCY DEVIATION Δf, and on the basis of the NETWORK POWER FREQUENCY CHARACTERISTICS λ_1 and λ_2 of the two separate networks, the following power values will be activated by PRIMARY CONTROL:

$$\Delta P_1 = -\lambda_1 \bullet \Delta f$$

$$\Delta P_2 = -\lambda_2 \bullet \Delta f$$

The loss of power P_a will be offset by the power values ΔP_1 and ΔP_2 : $\Delta P_1 + \Delta P_2 = -\Delta P_a$, and the frequency will be stabilised at a lower value, reduced by Δf.

c) Behaviour of SECONDARY CONTROL

The exchange power ΔP between the two CONTROL AREAS will no longer be zero, but becomes $\Delta P_{12} = \Delta P_1$, considered from CONTROL AREA 1, is an exported power, i.e. has a positive value, ΔP_{21} $(= -\Delta P_{12})$, considered from CONTROL AREA 2, is an imported power, i.e. has a negative value.

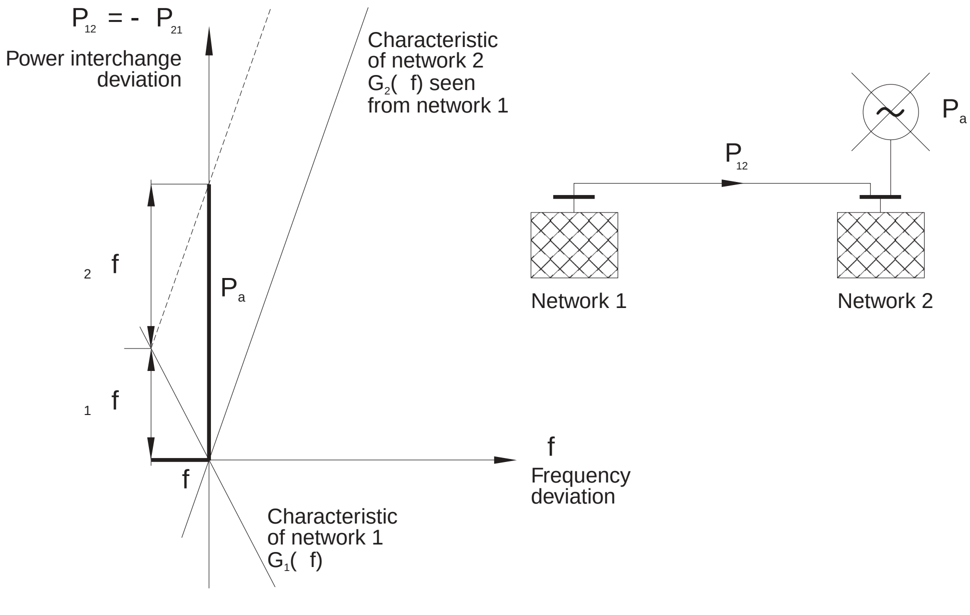
Under the condition that the value of K_{r1} is set at λ_1 on controller 1, and the value of K_{r2} is set at λ_2 on controller 2, this will give the following relationship for the overall control deviations G_1 and G_2:

$$G_1 = \Delta P_{12} + K_{r1} \bullet \Delta f = \Delta P_1 + (-\Delta P_1) = 0$$

i.e. controller 1 does not react, and PRIMARY CONTROL in CONTROL AREA 1 will be maintained as long as a Δf persists; no SECONDARY CONTROL will be activated in CONTROL AREA 1. For area 2, the AREA CONTROL ERROR is given by:

$$G_2 = \Delta P_{21} + K_{r2} \bullet \Delta f = -\Delta P_1 + (-\Delta P_2) = \Delta P_a$$

i.e. controller 2 activates SECONDARY CONTROL, and PRIMARY CONTROL in CONTROL AREA 2 will be maintained as long as a Δf persists; the loss of power P_a will be offset by the action of the SECONDARY CONTROLLER in area 2, such that the deviation associated with the loss of power P_a will be restored to zero.



If SECONDARY CONTROL is to behave as described above, the following conditions need to be fulfilled:

- Power plants involved in SECONDARY CONTROL must have sufficient SECONDARY CONTROL POWER available at all times, thereby ensuring that a change in the setting of the SECONDARY CONTROLLER will produce an actual change in power produced by generating sets (SECONDARY CONTROL RESERVE), see ⏩A1-B-6.
- G_i may not include any additional term, e.g. a corrective term for the automatic minimisation of an involuntary hourly exchange or any other form of compensation.

3. K-Factor

In order to ensure that SECONDARY CONTROL will only be called up in the CONTROL AREA / BLOCK which is the source of the disturbance, all values for K-FACTORS K_{ri} set on the

SECONDARY CONTROLLERS should, in theory, be equal to the CONTROL AREA's POWER SYSTEM FREQUENCY CHARACTERISTIC λ_1 (if the Darrieus equation is to be satisfied).

The NETWORK POWER FREQUENCY CHARACTERISTIC of a CONTROL AREA will change in accordance with the rated load of generator sets in service at any given time. Consequently, it might be envisaged that K_{ri} should be adjusted regularly to take account of generators in service. However, this is to be avoided, since the uncoordinated adjustment of K_{ri} by the various interconnection partners will produce greater discrepancies in their respective SECONDARY CONTROL behavior than those associated with the preservation of the various K_{ri} at constant values.

Due to the uncertainty on the self regulating effect of the load, the K-FACTOR K_{ri} may be chosen slightly higher than the rated value of the POWER SYSTEM FREQUENCY CHARACTERISTIC such that the SECONDARY CONTROL will accentuate the effect of the PRIMARY CONTROL and not counteract it.

4. Secondary Controller

The desired behaviour of the SECONDARY CONTROLLER over time will be obtained by assigning a proportional-integral characteristic (PI) to control circuits, in accordance with the following equation:

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

where:

ΔP_{di} = the correcting variable of the SECONDARY CONTROLLER governing control generators in the CONTROL AREA i ;

B_i = the proportional factor (gain) of the SECONDARY CONTROLLER in CONTROL AREA i ;

T_r = the integration time constant of the SECONDARY CONTROLLER in CONTROL AREA i ;

G_i = the AREA CONTROL ERROR (ACE) in CONTROL AREA i.

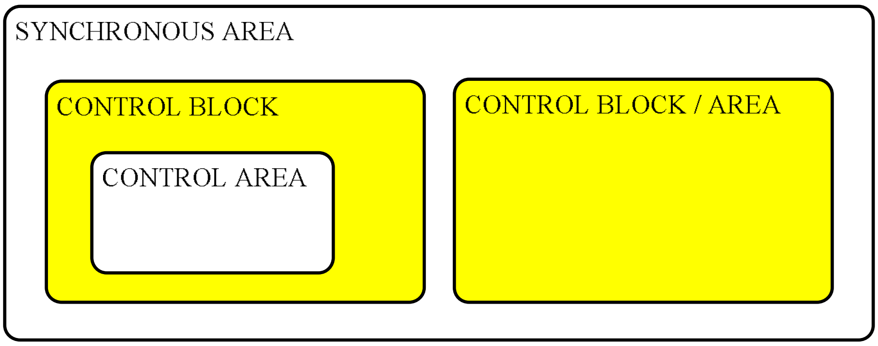
As SYSTEM FREQUENCY and POWER DEVIATIONS are to return to their set point values within the required time (without additional control needed), an appropriate integral term needs to be applied. An excessively large proportional term may have a detrimental effect upon the stability of interconnected operation. In particular, where hydroelectric plants are used for SECONDARY CONTROL, there is a risk that an increase in the proportional term will initiate network oscillations. This natural period of oscillation may range from 3 to 5 seconds, and may be subject to change as the SYNCHRONOUS AREA is extended.

In case of a persisting positive or negative ACE, leading to a saturation of the SECONDARY CONTROL RESERVES, the integral term should be limited. The non-windup character of the SECONDARY CONTROLLER allows to recover control as soon as the ACE returns to zero.

Parameter settings for SECONDARY CONTROLLERS of all CONTROL AREAS / BLOCKS need to follow a common guideline to ensure co-operative SECONDARY CONTROL within the SYNCHRONOUS AREA.

5. Control Hierarchy and Organisation

The SYNCHRONOUS AREA consists of multiple interconnected CONTROL AREAS / BLOCKS, each of them with centralised SECONDARY CONTROL. Each CONTROL AREA / BLOCK may divide up into sub-control areas that operate their own underlying SECONDARY CONTROL, as long as this does not jeopardise the interconnected operation. The hierarchy of SECONDARY CONTROL consists of the SYNCHRONOUS AREA, with CONTROL BLOCKS and (optionally) included CONTROL AREAS, see the following figure:



If a CONTROL BLOCK has internal CONTROL AREAS, the CONTROL BLOCK organises the internal SECONDARY CONTROL according to one of the following schemes (basically, the type of internal organisation must not influence the behaviour or quality of SECONDARY CONTROL between the CONTROL BLOCKS):

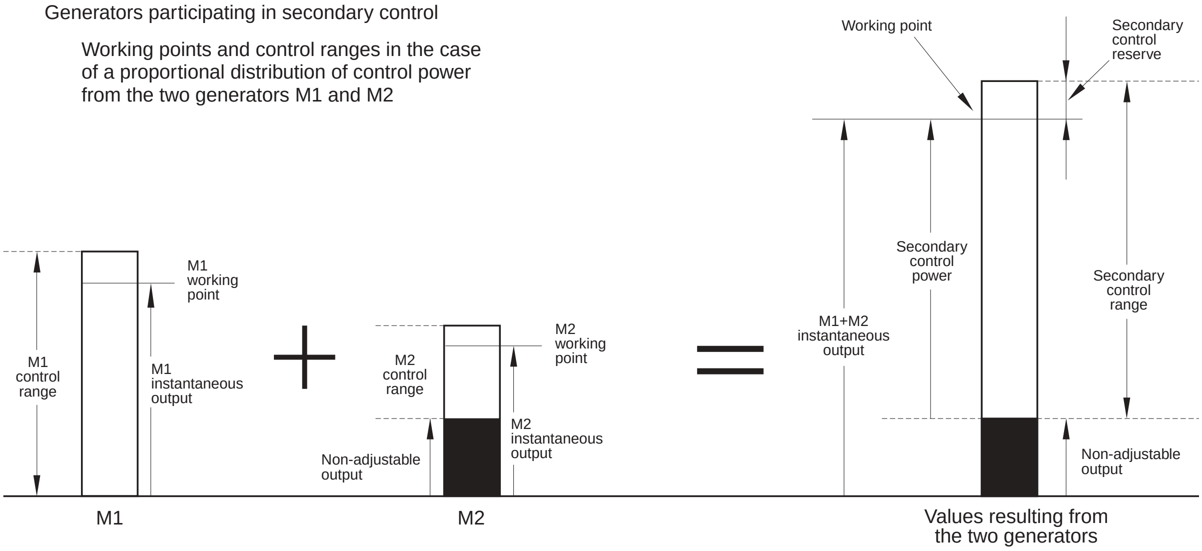
- **Centralised**: SECONDARY CONTROL for the CONTROL BLOCK is performed centrally by a single controller (as one CONTROL AREA); the operator of the CONTROL BLOCK has the same responsibilities as the operator of a CONTROL AREA.
- **Pluralistic**: SECONDARY CONTROL is performed in a decentralised way with more than one CONTROL AREA; a single TSO, the BLOCK CO-ORDINATOR, regulates the whole block towards its neighbours with its own controller and regulating capacity, while all the other TSOs of the block regulate their own CONTROL AREAS in a decentralised way by their own;
- **Hierarchical**: SECONDARY CONTROL is performed in a decentralised way with more than one CONTROL AREA; a single TSO, the BLOCK CO-ORDINATOR, operates the superposed block controller which directly influences the subordinate controllers of all CONTROL AREAS of the CONTROL BLOCK; the BLOCK CO-ORDINATOR may or may not have regulating capacity on its own.

6. Secondary Control Range and Reserve

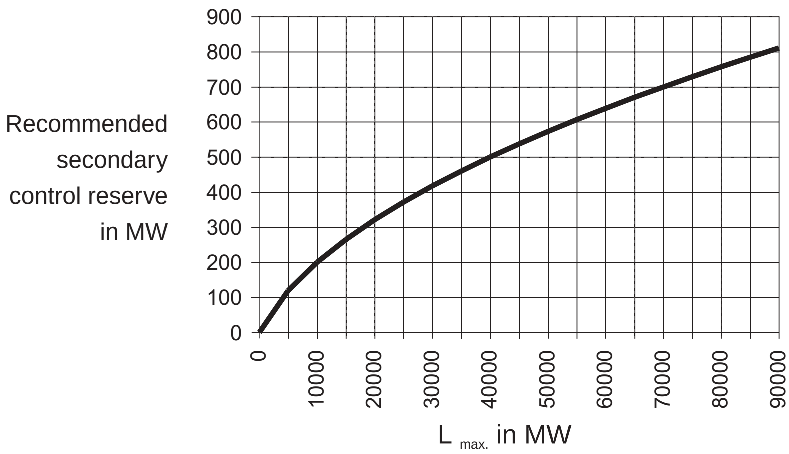
The SECONDARY CONTROL RANGE is the range of adjustment of the SECONDARY CONTROL POWER, within which the SECONDARY CONTROLLER can operate automatically, in both directions (positive and negative) at the time concerned, from the working point of the SECONDARY CONTROL POWER.

The SECONDARY CONTROL RESERVE is the positive part of the SECONDARY CONTROL RANGE between the working point and the maximum value. The portion of the SECONDARY CONTROL RANGE already activated at the working point is the SECONDARY CONTROL POWER.

The size of the SECONDARY CONTROL RESERVE that is required typically depends on the size of typical load variations, schedule changes and generating units. The recommended minimum reserve related to load variations is given in the following figure:



If the consumption exceeds production on a continuous basis, notwithstanding the availability of this reserve capacity, immediate action must be taken to restore the balance between the two (by the use of TERTIARY CONTROL, standby supplies, contractual load variation / LOAD-SHEDDING (some countries refer to ”load interruption”) or the LOAD-SHEDDING of a proportion of customer load as a last resort). Sufficient transmission capacity must be maintained at all times to accommodate reserve control capacity and standby supplies (see ⏩A1-C).



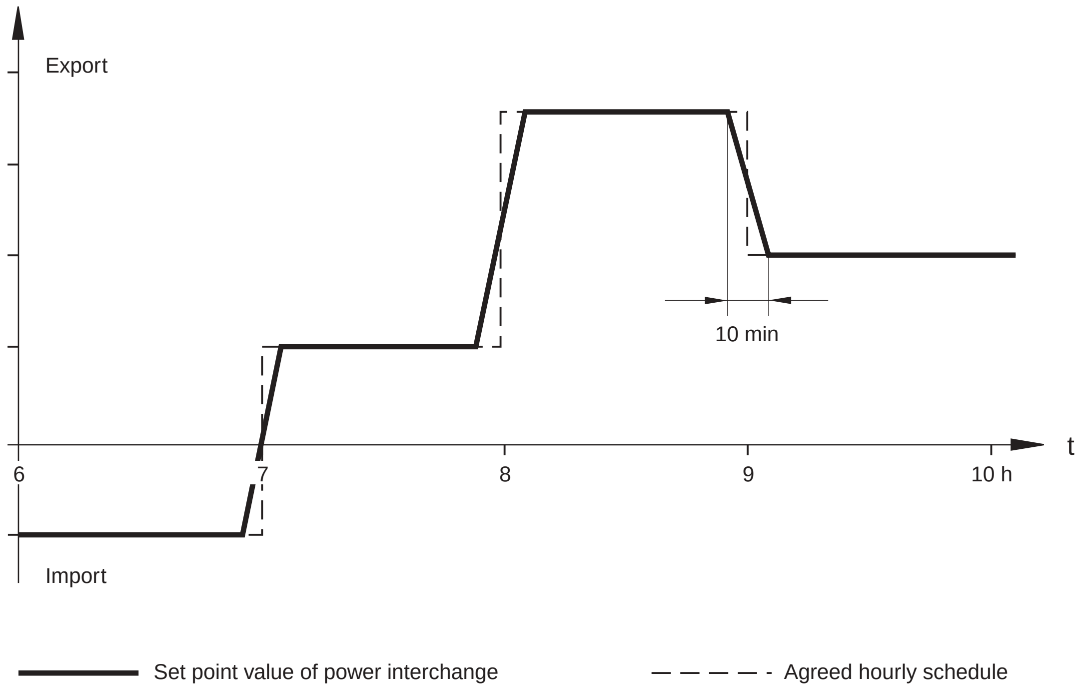
The rate of change in the power output of generators used for SECONDARY CONTROL must in total be sufficient for SECONDARY CONTROL purposes. It is defined as a percentage of the rated output of the control generator per unit of time, and strongly depends upon the type of generator[3]. Typically, for oil- or gas-fired power stations, this rate is of the order of 8% per minute. In the case of reservoir power stations, the rate of continuous power change ranges from 1.5 to 2.5% of the rated plant output per second. In hard coal- and lignite-fired plants, this rate ranges from 2 to 4% per minute and 1 to 2% per minute respectively. The maximum rate of change in output of nuclear power plants is approximately 1 to 5% per minute. These sample figures for customary rates of change in SECONDARY CONTROL action will be used as an aid to the definition of an optimum offset correction time.

7. Exchange Programs

The algebraic sum of the agreed hourly EXCHANGE PROGRAMS of cross-border exchange transfers between CONTROL AREAS / BLOCKS and the ADJACENT CONTROL AREAS constitutes

3: The type of generators that may be used for SECONDARY CONTROL within a CONTROL AREA depends on the generation mix / primary energies available in that geographical area and is therefore not evenly distributed in the SYNCHRONOUS AREA.

the power interchange set point for the CONTROL AREAS' SECONDARY CONTROLLER. In order to prevent excessive fluctuations on interconnections when program changes occur, it is necessary that this jump is converted to a ramp lasting 10 minutes in total, starting 5 minutes before the agreed change of the EXCHANGE PROGRAM and ending 5 minutes later (see example in figure below), regardless of the time-step (one hour, 30 minutes or 15 minutes) or the step size of the schedule (see ⏩P2 and ⏩A2 for further details of scheduling and accounting).



In order to prevent unintentional FREQUENCY DEVIATIONS and major control actions under undisturbed conditions, TRANSMISSION SYSTEM OPERATORS (TSOs) are required to maintain careful compliance with times for programme changes, particularly where changes in the EXCHANGE PROGRAMS 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 of he 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.

8. Quality of Control during Normal Operation

In order to allow the continuous monitoring of the quality of SECONDARY CONTROL, the FREQUENCY DEVIATION is evaluated statistically each month by determining the standard deviation σ:

$$\sigma = \sqrt{\frac{1}{n} \cdot \sum_{i=1}^{n} \left(f_i - f_0\right)^2}$$ (*n* is the number of average values over 15 minutes)

and the number and duration of frequency corrections. FREQUENCY DEVIATIONS $|\Delta f| >$ 50 mHz must also be monitored with respect to the frequency set-point, and the proportion of time during which $|\Delta f|$ exceeds 50 mHz must also be measured.

9. Quality of Control during Large Deviations

The quality of SECONDARY CONTROL must be monitored by measuring and analysing control in individual CONTROL AREAS / BLOCKS after losses of generating capacity or load exceeding 1000 MW[4] (observation incident).

The necessary data will be provided by the TSOs / interconnected undertaking concerned. Measurements of SYSTEM FREQUENCY and power interchanges behaviour during an incident allows a statistical analysis of PRIMARY and SECONDARY CONTROL performance.

The reaction or response of the SYNCHRONOUS AREA to a major disturbance P_a (generator shutdown or loss of load) in a CONTROL AREA / BLOCK and the return of the SYSTEM FREQUENCY f to its initial value (quality of SECONDARY CONTROL) are monitored by using the "trumpet method", described here after.

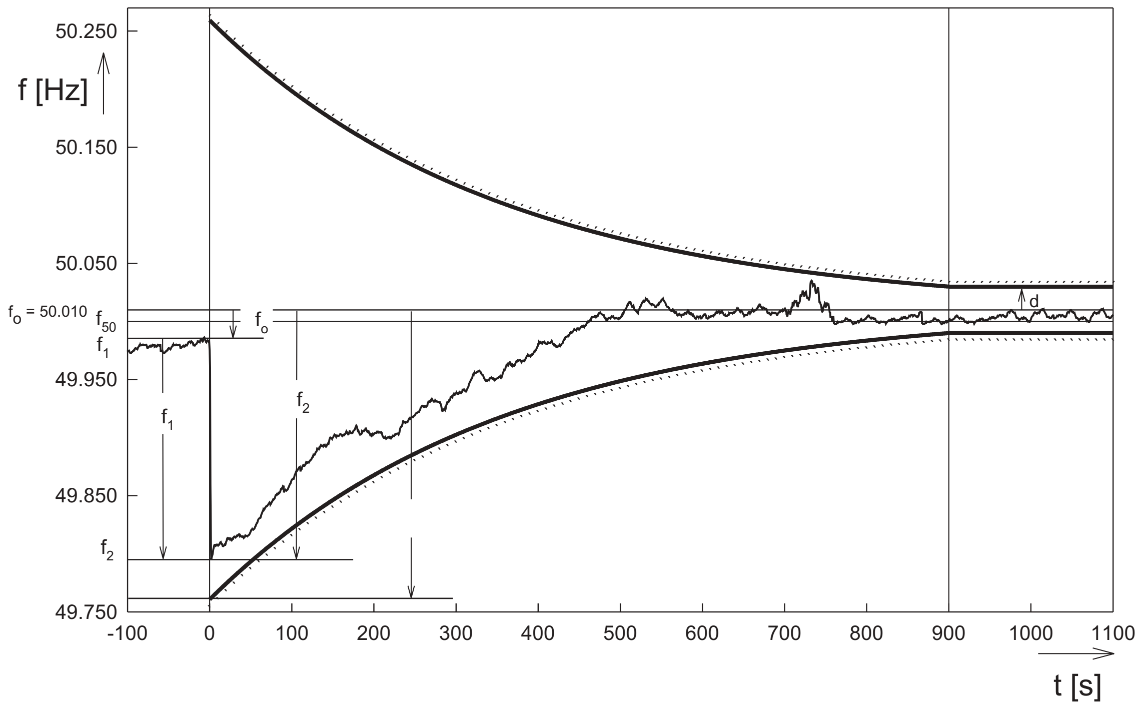
In order to assess the quality of SECONDARY CONTROL in CONTROL AREAS / BLOCKS, trumpet-shaped curves of the type $H(t) = f_0 \pm A \cdot e^{-t/T}$ have been defined on the basis of values obtained from experience and the monitoring of SYSTEM FREQUENCY over a period of years. When the SYSTEM FREQUENCY is maintained within the trumpet during the SECONDARY CONTROL process, the completion of the latter is deemed to be satisfactory, in terms of technical control.

The trumpet curve for a given incident will be plotted using the following values (see figure below):

- the set-point frequency f_0 (on the figure below, f_0 = 50.01 Hz)
- the actual frequency f_1 before the incident (on the figure below, f_1 is different from f_0)
- the maximum frequency deviation Δf_2 after the incident, with respect to the set-point f_0
- the loss of generating capacity ΔP_a responsible for the incident.

The following relationship between the above mentioned parameters do apply (see next figure):

$$\Delta f_2 = f_2 - f_0 = \Delta f_1 + \Delta f_0$$



The following relationship will apply to the trumpet curve (envelope curve) $H(t)$

$$H(t) = f_0 \pm A \cdot e^{-t/T}$$

[4] The value of 1000 MW holds for the first synchronous zone only, for the second synchronous zone the value currently is 250 MW instead.

The value A is established on the basis of frequency monitoring over a period of years for $A = 1.2 \cdot \Delta f_2$

The SYSTEM FREQUENCY must be restored to a margin of $d = \pm 20\, mHz$ of the set point frequency 900 seconds (15 minutes) after the start of an incident. Hence, the time constant T of the trumpet curve is determined by the following formula:

$$T = \frac{900}{\ln\left(\frac{A}{d}\right)} \qquad \text{for } T \le 900\, s \quad \text{and} \quad |d| = 20\, mHz$$

The series of curves described hereafter and shown on the figure below indicate the SYSTEM FREQUENCY response required after a given loss of power ΔP_a.

The following relationship will apply after the loss of ΔP_a:

$$\lambda_u = \frac{\Delta P_a}{\Delta f_1} \text{ or } \Delta f_1 = \frac{\Delta P_a}{\lambda_u}$$

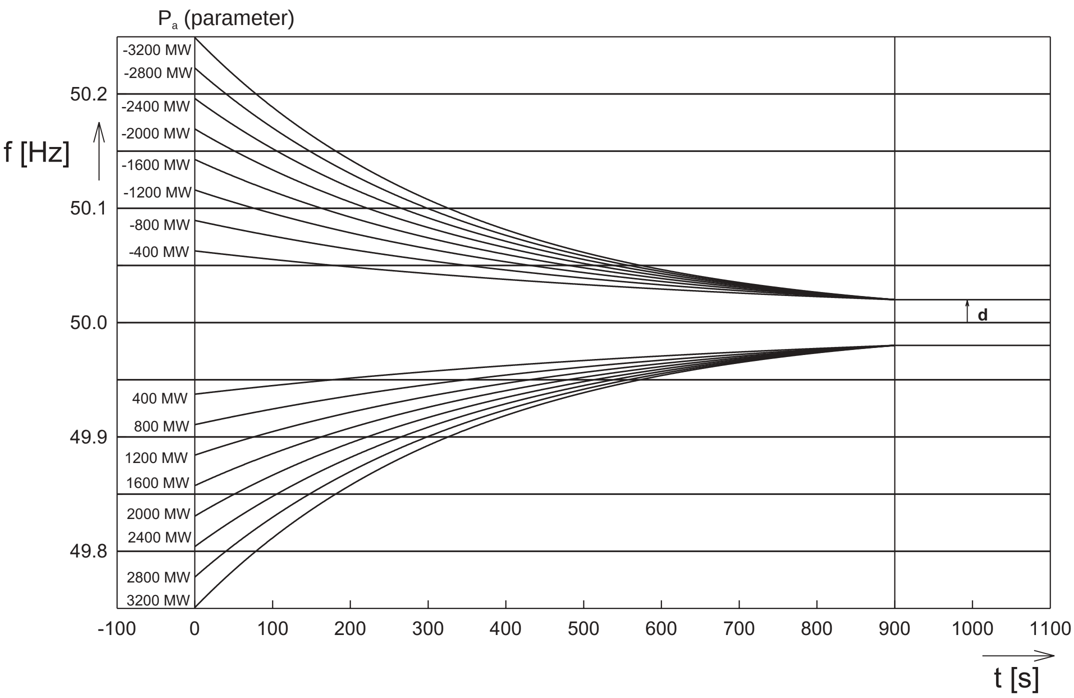
For each loss of power, this relationship gives the corresponding frequency deviation Δf_1.

Frequency monitoring over many years has shown that the FREQUENCY DEVIATION Δf_0 is often greater (up to ±30 mHz) before an incident than after the secondary control process (up to ±20 mHz). This is due to the insensitivity of PRIMARY and SECONDARY CONTROL and the inaccuracy of the measurements. In the series of curves, this is taken into account by a general increase of 30 mHz in factor A^*:

$$A^* = \pm 1.2 \cdot \left(|\Delta f_1| + 30\, mHz\right) = \pm 1.2 \cdot \left(\frac{1}{\lambda_u} \cdot |\Delta P_a| + 30\, mHz\right)$$

All other initial values will remain the same. This gives the following for the series of curves $H^*(t)$
with ΔP_a as parameter:

$$H^*(t, \Delta P_a) = f_0 \pm A^* \cdot e^{-t/T}, \quad H^*(t, \Delta P_a) = f_0 \pm 1.2 \cdot \left(\frac{1}{\lambda_u} \cdot |\Delta P_a| + 30\, mHz\right) \cdot e^{-t/T}$$



The SYSTEM FREQUENCY itself depends on a lot of other circumstances, physical effects and underlying control mechanisms (see ⏩A1-A), that cannot be clearly distinguished in all cases. Therefore, the analysis is usually made on a case-by-case basis.

C. Tertiary Control

[UCTE Operation Handbook Policy 1 Chapter C: Tertiary Control, 2004]

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

1. Introduction

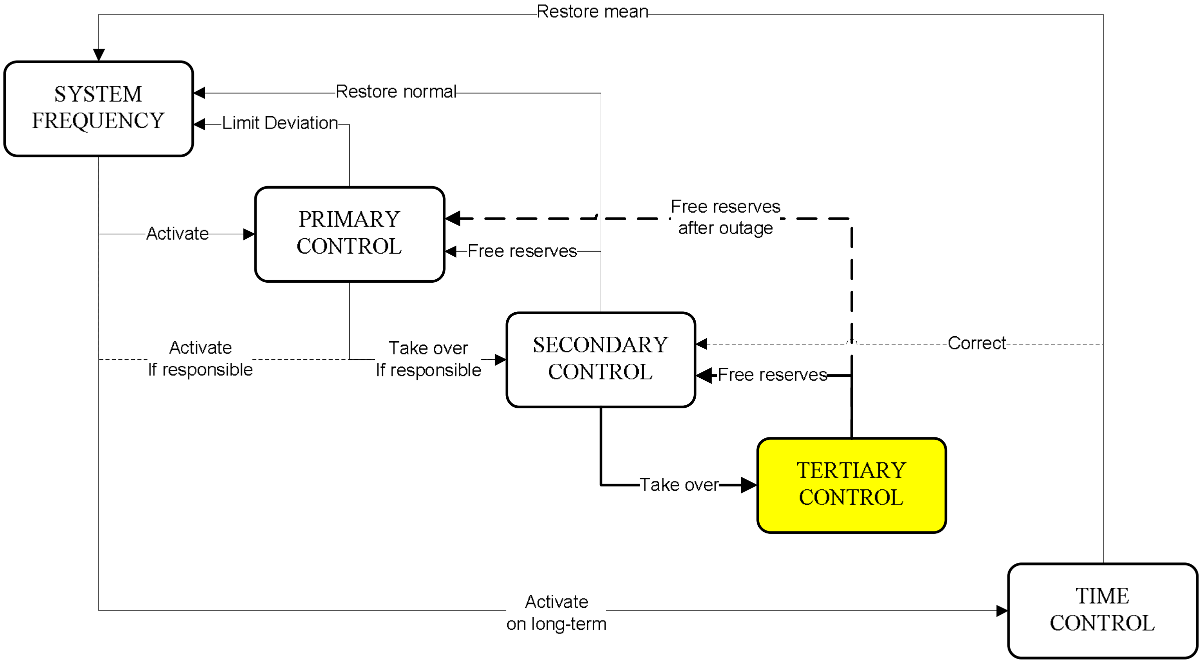
TERTIARY CONTROL is any automatic or manual change in the working points of generators or loads participating, in order to:

- guarantee the provision of an adequate SECONDARY CONTROL RESERVE at the right time,
- distribute the SECONDARY CONTROL POWER to the various generators in the best possible way, in terms of economic considerations.

Changes may be achieved by:

- connection and tripping of power (gas turbines, reservoir and pumped storage power stations, increasing or reducing the output of generators in service);
- redistributing the output from generators participating in secondary control;
- changing the power interchange programme between interconnected undertakings;
- load control (e.g. centralised telecontrol or controlled LOAD-SCHEDDING).

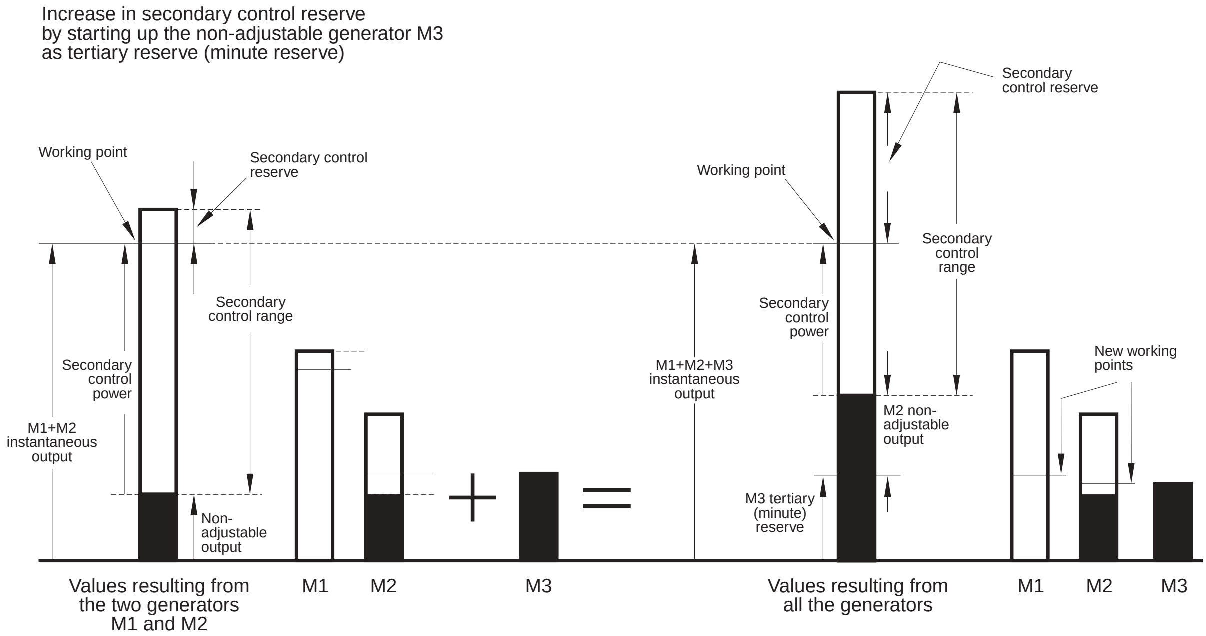
Typically, operation of TERTIARY CONTROL (in succession or as a supplement to SECONDARY CONTROL) is bound to the time-frame of SCHEDULING, but has on principle the same impact on interconnected operation as SECONDARY CONTROL.



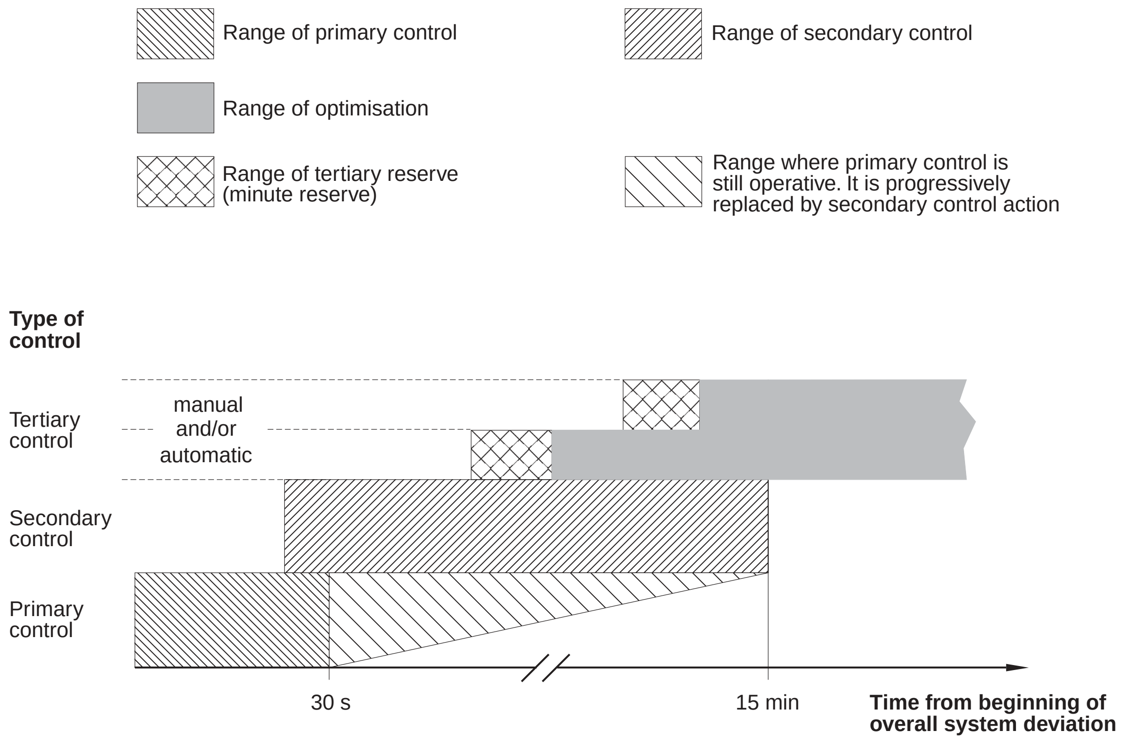
2. Tertiary Control Reserve

The power which can be connected automatically or manually under TERTIARY CONTROL, in order to provide / restore an adequate SECONDARY CONTROL RESERVE, is known as the TERTIARY CONTROL RESERVE / 15 minute reserve[5]. This TERTIARY CONTROL RESERVE must be used in such a way that it will contribute to the restoration of the SECONDARY CONTROL RANGE when required (see ⏩A1-B for details on SECONDARY CONTROL).

5: Because of the typical time-frame for SCHEDULING of 15 minutes.



The restoration of an adequate SECONDARY CONTROL RANGE may take, for example, up to 15 minutes, whereas TERTIARY CONTROL for the optimisation of the network and generating system will not necessarily be complete after this time. The timing of the various (partially overlapping) ranges of action of PRIMARY, SECONDARY and TERTIARY CONTROL are shown in the following figure.



3. Capacity Constraints

The following non-usable capacity must be taken into account in the calculation of capacity needed to meet power requirements:

- units subject to long-term shutdown;
- units shut down for repair and maintenance;
- limits on capacity associated with restrictions in fuel supplies (e.g. restrictions on gas supplies during the peak winter months);

- limits on capacity associated with environmental restrictions (e.g. temperature of waste water in summer, pollution, etc.);
- limits on the capacity of hydroelectric plants associated with hydraulic and environmental constraints (e.g. output restrictions, etc.);
- the primary control reserve;
- reserves to cover variations in production and consumption (secondary and tertiary reserves).

In addition to these factors, which are directly associated with production, account must also be taken of system conditions, given that network constraints may reduce scope for the transmission of power produced.

D. Time Control

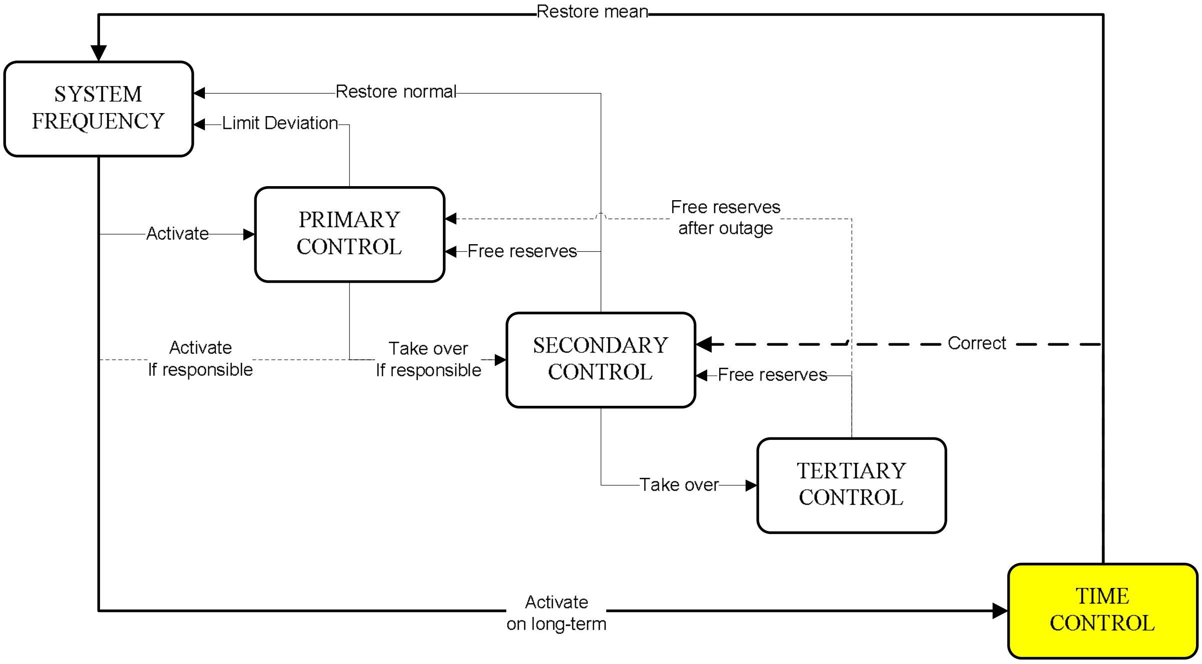
[UCTE Operation Handbook Policy 1 Chapter D: Time Control, 2004]

[UCPTE Rule: Technical rule for the correction of synchronous time, 1998]

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

1. Summary

If the mean SYSTEM FREQUENCY in the SYNCHRONOUS ZONE deviates from the nominal frequency of 50 Hz, this results in a discrepancy between SYNCHRONOUS TIME and universal coordinated time (UTC). This time offset serves as a performance indicator for PRIMARY, SECONDARY and TERTIARY CONTROL (power equilibrium) and must not exceed 30 seconds. The Laufenburg control centre in Switzerland is responsible for the calculation of SYNCHRONOUS TIME and the organisation of its correction. Correction involves the setting of the set-point frequency for SECONDARY CONTROL in each CONTROL AREA / BLOCK at 49.99 Hz or 50.01 Hz, depending upon the direction of correction, for full periods of one day (from 0 to 24 hours).



The quality of SYSTEM FREQUENCY will be regarded as satisfactory over a one month period:

- where the standard deviation for 90% and 99% of measurement intervals is less than 40 mHz and 60 mHz respectively for the whole month considered;
- where the number of days' operation at a set point frequency of 49.99 Hz or 50.01 Hz does not exceed eight days per month respectively (to be confirmed by experience).

E. Measures for Emergency Conditions

[UCTE Operation Handbook Policy 1 Chapter E: Measures for Emergency Conditions, 2004]

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

[UCPTE Rule 33: Recommendations for measures for frequency control and large disturbances, 1983]

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

1. Introduction

The direct measures for emergency conditions are based to a certain extent on the philosophy that in the event of a major disruption (short-term and where possible), selective restrictions in the energy supply are more acceptable then the consequences of an extended network breakdown resulting in a power cut lasting for several hours. The main principles of “Operational Security” are described in policy 3 (see ⏩P3).

The SYSTEM FREQUENCY as a global parameter is the main criterion that signalises emergency situations in the system. Due to its equal value in the interconnected system, all partners are automatically participating at problem solving by the automatic action of the PRIMARY CONTROLLERS (see ⏩A1-A). Local indicators, that inform about possible emergency situations, are “overloading of the interconnecting TIE-LINES” that can result in action of automatic protection devices and isolating of some part of the system. Important local signals of the emergency situation are also “decreasing of the transmission voltage” that can cause voltage collapse due to abnormally high flow of reactive power in the transmission system.

Counteraction of the SECONDARY CONTROLLER and the measures for emergency conditions (e.g. in the scope of system defence during a big drop of frequency) shall be avoided in a co-ordinated way.

2. Recommendations for Load-Shedding

Frequency thresholds must be defined for LOAD-SHEDDING. The UCTE recommends that its members should initiate the first stage of automatic load-shedding in response to a frequency threshold not lower than 49 Hz.

- Sudden failure of 3000 MW of the generating capacity in normal operation without other disruptions have to be corrected solely by the action of the PRIMARY CONTROLLER without frequency sensitive action triggering of LOAD-SHEDDING.
- In case of a frequency drop of 49 Hz the automatic LOAD-SHEDDING begins with a minimum of 10 to 20% of the load. Each TSO determines shedding plans on his own. In case of lower SYSTEM FREQUENCIES, the synchronously interconnected network may be divided into partial networks. In this case, far more difficult conditions will arise in those partial networks affected by a shortfall in capacity. For this reason, the staggered operation of relays for LOAD-SHEDDING in response to a frequency criterion will allow the system load to be reduced to a sufficient extent for the restoration of balanced conditions in these partial networks, before the threshold for the isolation of plants for the supply of auxiliaries or the tripping of generators is reached.

LOAD-SHEDDING should be performed at trigger frequencies of 48.7 Hz and 48.4 Hz (or as in France at 48.5 Hz and 48.0 Hz) to the amount of about 10 to 15% of the load. The partners accept LOAD-SHEDDING also if the failure occurs outside the CONTROL AREA of the respective TSO. Triggering frequencies should be modified by the competent TSO - slight dissipation of the triggers will cause gradual increasing of the load.

- LOAD-SHEDDING in each stage shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

3. Recommendations for Power Plants

The following possible measures for emergency conditions are related to power plants:

- At 49.8 Hz, quick-start power plants should be connected to the grid.
- Under emergency conditions and if applicable, the operating mode of (thermal) generating units should/may be changed from power pressure into speed control. A very fast rate of change can be possible within the whole operating range, yet being very uneconomic.

- Power stations automatically disconnect at 47.5 Hz[6] without time delay, and shall safeguard auxiliary service supply. Operation of power plants below this frequency is endangered (loss of capacity in the auxiliary gear, danger vibration, damage of the blade and foundations).

4. Recommendations for power plants regarding U/Q control

Measures for emergency conditions regarding U/Q control can be supported by:

- transformers with regulation on-load tap changing device
- static compensation

Measures must be taken to maintain reactive power near to the point of consumption to ensure minimal transfer of reactive power through the network.

6: The critical negative limit of the SYSTEM FREQUENCY of 47.5 HZ (and the positive limit of 52.5 Hz as well) are known to be critical for generation sets, because this may trigger automatic disconnection of generators for safety reasons.