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Modelling of Control Systems and Optimal Operation of Power Units in Thermal Power Plants

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Declaration:
Hereby I declare that this doctoral thesis, my original investigation and achievement, submitted for the doctoral degree at Tallinn University of Technology has not been submitted for any academic degree.

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ENERGEETIKA. ELEKTROTEHNIKA. MÄENDUS D71

Energiaplokkide juhtimissüsteemide modelleerimine ja talitluse optimeerimine soojuselektrijaamades

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TTÜ KIRJASTUS

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LIST OF ORIGINAL PAPERS

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I. R. Attikas, H. Tammoja. Excitation system models of generators of Balti and Eesti power plants. Oil Shale, 2007, Vol.24, No. 2 Special, pp. 285-295. Estonia Academy Publishers ISSN 0208-189X

II. H. Tammoja, R. Attikas, J. Shuvalova. Calculation of input-output characteristics of power units under incomplete information. Oil Shale, 2007, Vol. 24, No. 2 Special, pp. 277-284. Estonia Academy Publishers ISSN 0208-189X

III V. Medvedeva-Tšernobrivaja, R. Attikas, H. Tammoja. Characteristic numbers of primary control in the isolated Estonian power system. Oil Shale, 2011, Vol. 28, No. 1 S, pp. 214–222. Estonia Academy Publishers ISSN 0208-189X

IV S. Pulkkinen, R.Attikas. Power and frequency control principles of different European synchronous areas. 11th International Symposium, Topical problems in the field of electrical and power engineering, Doctoral school of energy and geotechnology II, Pärnu, Estonia, January 16-21, 2012. pp. 200-204

In appendix A, copies of these papers have been included

Author's own contribution

The contribution by the author to the papers included in the thesis is as follows:

I. Raivo Attikas wrote the paper and is the corresponding author. He was responsible for literature overview, data collection and modelling.
II. Raivo Attikas participated in writing the paper. He was responsible for literature overview, data collection and some of the calculation.
III. Raivo Attikas participated in writing the paper. He was responsible for literature overview, data collection and interpreted the results.
IV. Raivo Attikas participated in writing the paper. He was responsible for literature overview, data collection and interpreted the results.

INTRODUCTION

This thesis proposes models for the Eesti and the Balti Power Plant units intended for the stability studies of the Estonian power system (hereinafter "power system" denotes electrical transmission network only). Next, the Estonian power system, including the Eesti and the Balti Power Plant, will be briefly introduced.

Estonian power system is interconnected and operates synchronously with Russian, Latvian, Lithuanian and Belorussian power systems. The Russian power system operates synchronously also with the power systems of Ukraine, Azerbaijan, Georgia, Kazakhstan, Moldova and Mongolia. Through Kazakhstan, the Russian power system is further synchronously interconnected with the power systems of Kyrgyzstan and Uzbekistan [1]. In addition, the Estonian power system has an interconnection via high voltage direct current (HVDC) transmission links with the Nordel power system. Currently two HVDC lines are in operation between the Estonian and Finnish power systems. The first HVDC link, called Estlink 1, started operating in November 2006 with a net capacity of 350 MW. The second HVDC link, Estlink 2 with a net capacity of 650 MW is in commercial operation since February 2014. The current total transmission capacity between the Estonian and the Finnish power system is approximately 1000 MW [2]. The maximum load of the Estonian power system is approximately 1540 MW, while the summer time maximum load is within the range of 900 – 1000 MW.

There are two large power plants in the Estonian power system: the Eesti Power Plant and the Balti Power Plant with an available capacity of 1355 and 432 MW, respectively. The total installed capacity of all other power plants in the Estonian power system is about 640 MW, from which wind parks provided 276 MW as of September 2013 [3]. Therefore, the Eesti Power Plant and the Balti Power Plant are extremely important for securing operational reliability in the Estonian power system.

The Balti Power Plant built in 1959-1965 is located about 5 km southwest of the Narva town center. The designed electrical capacity of the Balti Power Plant was 1624 MW, and the thermal capacity was 505 MW. According to initial design, 12 units were built in the Balti Power Plant [4]. Currently, only 3 units are in operation, each unit having one turbine and two boilers. In the second half of 2004, one 200 MW power unit at the Balti Power Plant was repowered. The steam turbine was modernized and upgraded to 215 MW. The modernized unit has two circulating fluidized bed (CFB) boilers as well as a renewed generator control system, a new static excitation system UNITROL 5000 and a new turbine speed governor control system SIMADYN D. The other two units have pulverized fire (PF) boilers (boiler type ТП – 67, design dating from the 1960s, USSR), with the installed capacity of each unit 200 MW along with Soviet-made excitation systems and turbine speed governor systems. All the units of the Balti Power Plant are equipped with Soviet-made generators (type ТВВ – 200 – 2А) and steam turbines (type K – 200 – 130). The power plant unit with CFB boilers has a modernized generator, type TBB – 200 – 2AM [5].

The Eesti Power Plant built in 1963-1973 is located 25 km southwest of Narva. Eesti power plant has 8 units, each unit having one turbine and two boilers. Similarly to the Balti Power Plant, one unit in the Eesti Power Plant has been repowered. The steam turbine was modernized and upgraded to 215 MW. The modernized unit is equipped with two circulating fluidized bed (CFB) boilers and the unit has a renewed generator control system, a new static excitation system UNITROL 5000 along with a new turbine speed governor control system SIMADYN D. The other seven units have Soviet-made pulverized fire (PF) boilers (boiler type ТП-101), the installed capacity of each unit being 200 MW. One power plant unit with PF boilers is equipped with a new turbine speed governor control system Damatic XD launched in 2001. The other units with PF boilers have Soviet-made excitation systems and turbine speed governor systems. All the units have Soviet-made generators (type TBB – 200 – 2A) and steam turbines (type K – 200 – 130). Power plant units with CFB boilers have modernized TBB – 200 – 2AM type generators [5].

Importance of the study

Electricity plays an important role in modern human life. It is difficult to imagine people's daily routines without electricity and it is quite evident after some large power outages that in the civilized world even a few hours' absence of electricity can cause catastrophic consequences. Public services, factories, households, electric transport – all these key areas of human activity would be paralyzed during a blackout. Thus, uninterrupted and reliable operation of an electric power system as well as the quality of supplied power is increasingly important for modern society.

Many exceedingly large power failures have occurred in various parts of the world. One of the largest blackouts took place in the United States and Canada in the afternoon of 14 August 2003, starting from the area around Lake Erie and Ontario, and extending all the way to New York City. In that blackout 61800 MW of consumption was lost and the power failure impacted nearly 50 million people. For some electricity consumers, this failure lasted for more than 24 hours. On 23 September 2003, a blackout occurred in the southern Sweden and in areas of Denmark. Approximately 5000 MW of consumption was lost and the outage influenced almost 3.5 million people, some of them for nearly seven hours. Italy had a major power failure on 28 September 2003. Before the disturbance, the consumption in Italy was approximately 24600 MW, of which imports from the neighboring countries constituted almost 6700 MW. After a cascade of disturbances, the entire Italian power system went into blackout, which in some areas lasted for almost 20 hours [6]. On 4 November 2006 after tripping of several high voltage lines in Northern Germany, the continental Europe grid was split into three areas: West, North – East and South – East with significant power imbalance in each area. The power imbalance in the Western area induced a severe frequency drop that caused an interruption of supply for more than 15 million European households. The transmission system operators (TSOs) were able to restore a normal situation in all European countries in less than two hours [7]. On 30 and 31 July 2012, the world's largest blackout hit India. On 30 July a disturbance occurred in the Northern India electricity grid leading to a blackout in nearly the entire Northern region. Approximately 38000 MW out of the total 99700 MW load was affected by the grid disturbance. Another disturbance that occurred on 31 July affected the Northern, Eastern and North-Eastern electricity grids. From the total consumption of the Indian power system of 100500 MW, approximately 48000 MW was affected by the grid disturbance [8]. 30 and 31 July blackouts affected correspondingly about 300 and 600 million people, which makes them the largest blackouts of the world.

TSOs are responsible for providing reliable system operation, where power system planning has the key role. Therefore, a TSO must systematically analyze system behavior during disturbances in various system configurations during long-term and short-term planning. Adequate power system models are needed for system analysis. Furthermore, for system stability studies, modelling the generator and its auxiliary systems is the most important task. Generators, the source of active power, are providing voltage support, oscillation damping and frequency regulation.

In addition to ensuring uninterrupted reliable system operation, TSOs must ensure frequency quality. Close control of frequency ensures constant speed of induction and synchronous motors. Constant speed of motor drives is particularly important for satisfactory performance of the generating units of the thermal power plant as they are highly dependent on the performance of all the auxiliary drives associated with the fuel, the combustion air supply systems and especially the high pressure feed-water pumps. In a network, a considerable drop in frequency could result in high magnetizing currents in induction motors and transformers. The extensive use of electric clocks and the use of frequency for other timing purposes require accurate maintenance of synchronous time which is proportional to the mathematical integral of frequency.

Subject of the research

As was mentioned above, adequate power system models are needed for system analysis in order to provide reliable operation of the system. Thus, the main aim of this paper is to study the generator and the modelling aspects of its control system from the stability study perspective. The paper provides a concept for modelling generators with their auxiliary systems and modelling turbines with their auxiliary systems within stability studies of the Estonian power system.

This work also includes an overview of different types of dynamic stability and description of the influence of generators and their auxiliary systems on stability provision. Additionally, this paper describes the influence of different impact factors on the accuracy of modelling various types of stability.

For further analysis, the results of the isolation test performed on 3-4 April 2009 have been selected for this thesis, as it has been the latest isolation test so far and will therefore provide arguably the most accurate and representative background data for describing the capability and quality of the frequency regulation of the Estonian power system.

In addition to the above mentioned technical challenges, it is important to find the most economically beneficial way to dispatch a load between the power units and the boilers. Thus, a methodology is proposed for optimal load dispatch between the power units and the boilers under incomplete information.

Theoretical and practical originality of the work

The originality of the work and the key factors that distinguish this research from previous research are:

1. A new model is proposed for the AC machine excitation systems in the Eesti Power Plant and the Balti Power Plant units with the pulverized fire boilers, which allows dynamic stability studies of the Estonian power system by using the PSS/E software. This software is used by the Estonian TSO, thus models that can be used in PSS/E are examined in the thesis. An overview of different generator, static excitation system and turbine speed governor system models are presented for Eesti Power Plant and the Balti Power Plant units.
2. It is described how different generator models would influence the quality of the system stability analysis. For the stability studies of the Estonian power system a generator model is proposed, using the PSS/E software.
3. Model settings are presented for the generator, the excitation system and the speed governor models.
4. The capability and quality of the Estonian power system frequency regulation are analyzed on the basis of the Estonian power system isolation test performed on 3-4 April 2009. A methodology for the calculation of characteristic numbers of primary regulation is introduced and calculations have been done for all stages of the isolation test.
5. A practical methodology is proposed which enables a simple use of probabilistic and uncertain information in optimal load dispatching between the power plant units and the boilers.

Presentation of the research results

PAPER I introduces the excitation systems used in the Balti and the Eesti Power Plant units, also models are proposed for these excitation systems. Proposed models can be used in PSS/E for power system stability studies. PAPER II introduces a methodology that enables a simple use of probabilistic and uncertain information in the optimal dispatching of power plant units. The method of optimal dispatch in power plants which takes into account the probabilistic information about random factors enables economy of fuel by up to 1.5 %. PAPER III introduces a methodology that enables calculation of the characteristic numbers of primary control in the Estonian power system. This paper presents the characteristic numbers of primary control in the isolated Estonian power system (test performed on 3-4 April 2009) under the system contingencies such as the artificially created failure produced by switch offs of individual generation blocks and switch offs of the HVDC link. PAPER IV presents an overview of power and frequency control principles used in IPS/UPS and ENTSO-E RG CE synchronous areas. The paper compares the frequency control norms and standards of IPS/UPS and ENTSO-E RG CE systems and defines the main differences and similarities between them. Main challenges to interconnect synchronously IPS/UPS and ENTSO-E RG CE systems are also discussed.

The classification of power system stability is provided in Chapter 1. Also, rotor angle stability (including transient and small signal stability), voltage and frequency stability are described and discussed. Relationships between different stabilities and the generator with its auxiliary equipment are introduced. Chapter 2 analyzes generator modelling from the power system stability point of view. Chapters 3 and 4 focus on modelling of the excitation systems and the governor systems, respectively, from the power system point of view. Chapter 5 discusses frequency regulation principles and analyzes the quality of frequency regulation. The last chapter studies the methodologies of optimal load dispatch between the power plant units.

SYMBOLS

σ	root -mean-square of parameter
μ	wire magnetic permeability
B	total fuel costs of the power plant
BUe (PUe)	fuel cost characteristic of power unit e
C	fuel cost of the unit
c	price of fuel
D	damping constant
E_{FD}	exciter output voltage or synchronous machine field voltage
H	inertia constant
i	current
ia, ib, ic	phase currents
I_{FD}	exciter output current or synchronous machine field current
$\bar{I}_T$	synchronous machine terminal current phasor
Ke	amplification factor of exciter
Ke	voltage regulator gain
Kf	amplification factor of winding
Kffb	amplification factor of flexible feedback
k_i	correction coefficient of operation parameter deviation
KIA	active power compensation factor
KIR	reactive power compensation factor
KR	steady state gain
Krfb	amplification factor of rigid feedback
Kv	amplification factor of amplifier
L	induction
l	length of wire
m	mathematical expectations of parameter
P	net load of the power plant
P	power output of the unit
P_e	electrical power
P_L	load power
P_m	mechanical power
Q_T	heat input of the turbine
r	resistance
R_a	stator resistance
s	Laplace operator
s	wire cross-section
S(1.0), S(1.2)	saturation factors
T''_{do}	direct axis sub transient open circuit time constant
T''_{qo}	direct axis sub transient open circuit time constant
T'_{do}	direct axis transient open circuit time constant
T'_{qo}	direct axis transient open circuit time constant

T_a	accelerating torque
TB1	controller first lag time constant
TB2	controller second lag time constant
TC1	controller first lead time constant
TC2	controller second lead time constant
TD	damping torque coefficient
T_e	electrical torque
Te	exciter time constant
Te	gate control unit and converter time constant
t_e	voltage regulator time constant
Tffb	time constant of flexible feedback
T_m	mechanical torque
TR	measuring filter time constant
TS	synchronizing torque coefficient
Tv	amplifier time constant
U_C	output of terminal voltage transducer and load compensation elements
U_F	the field voltage
U_{FD}	change in the field voltage
U_{OEL}	over excitation limiter output
Up+ , Up-	AVR output positive and negative ceiling values correspondingly
U_R	voltage regulator output
U_{REF}	voltage regulator reference voltage
Us	power system stabilizer output
U_{SI}	power system stabilizer input
$\bar{U}_T$	synchronous machine terminal voltage phasor
U_t	the synchronous machine terminal voltage
U_{tD}	change in the synchronous machine terminal voltage
v	number of operating power units
VUEL	under excitation limiter output
w	number of spins
W1, K	amplification factor.
x''_d	direct axis sub transient reactance
x''_q	quadrature axis sub transient reactance
x'_d	direct axis transient reactance
x'_q	quadrature axis transient reactance
x_d	direct axis synchronous reactance
x_l	leakage reactance
x_q	quadrature axis synchronous reactance
ΔX_i^-	deviation of operation parameter towards the direction which reduces the incremental cost rate of the power unit
ΔXi^+	deviation of operation parameter towards the direction which increases the incremental cost rate of the power unit

$\Delta\delta$	rotor angle perturbation
$\Delta\omega$	speed deviation
λ	flux linkage
Θ	angle between the phase current

ABBREVIATIONS

AC	alternating current
AE	amplification element,
AFC	automatic frequency control
ANGLE	rotor angle
AVR	automatic voltage regulator
BRELL	Belorussia, Russia, Estonia, Latvia and Lithuania
BSF	black start function
CB	compensation block
CE	converting element
CFB	circulating fluidized bed
CIGRE	International Council on Large Electric Systems
EFD	field voltage
EMF	electromagnetic field
ENTSO-E	European Network for Transmission System Operators for Electricity
ETERM	terminal voltage
FCP	frequency containment process
FCR	frequency containment reserves
FFE	flexible feedback element
FRP	frequency restoration process
FRR	frequency restoration reserves
FU	forcing unit
GENCLS	constant internal voltage generator model
GENSAL	salient pole generator model
HPP	hydro power plant
HVDC	high voltage direct current
IEEE	Institute of Electrical and Electronics Engineers
IEEEG1	IEEE type 1 speed-governing model
ISORCE	source current
LFC	load-frequency control
ME	measuring element
MW	megawatt
MWh	megawatt hour
NPP	nuclear power plant
PF	pulverized firing
PMECH	mechanical power
PSS	power system stabilizers
PSS/E	Power System Simulator for Enineering
RR	replacement reserves
RRP	reserves replacement process
SCADA	Supervisory control and data acquisition

SPEED	speed deviation
TPP	thermal power plant
TSO	transmission system operators
TUT	Tallinn University of Technology
UCTE	Union for the Co-ordination of Transmission of Electricity
VOLT	voltage at terminal bus

1. Dynamics in power systems

Many different types of dynamics occur in power systems. Each dynamic is characterized by different parameters such as a cause of origin, its duration, an influence on the processes in the power system and the area of involvement. If a dynamic has a local influence, only a few elements of the system or a small part of the system is involved. If a dynamic has a global influence, the different parts of the system, which might be geographically far from each other can be involved due to interactions between them. These interactions cause disturbances in the normal system operation that can lead to system instability and, in extreme cases, to blackout in the system.

Dynamic phenomena in power systems are usually classified as [9]:

1. Fast (electro-magnetic) transients (100 Hz – MHz)
2. Electro-mechanical swings (rotor swings in synchronous machines) (0.1 – 3 Hz)
3. Non-electric dynamics, e.g. mechanical phenomena and thermodynamics (up to tens of Hz)

One single event in the power system can cause dynamics in all the three groups. For instance, a lightning stroke into a power line pylon can induce so high over-voltages that the power line insulation fails, which in turn will induce an earth fault. The earth fault can cause rotor swings in synchronous machines with high amplitudes, which in turn can trigger the generator protection system to disconnect generators from the power system. Generator disconnection will cause imbalance between the produced and the consumed power in the system. Therefore, frequency in the system will drop and generators, which are participating in the frequency control, will compensate active power imbalance by increasing their power generation [9].

1.1. Classification of power system stability

Over the years many different definitions of power system stability have been proposed. This thesis presents the definition prepared by the IEEE/CIGRE joint working group [10]:

Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that the entire system remains intact.

The operating equilibrium re-established by the system after disturbance can differ from its initial steady state level. This situation could occur if the disturbance has caused the outage of any power system element (for instance, the generator or line). In such a case, voltage and power flows after the disturbance will differ from their initial values. The disturbances can cause not only the tripping of a single power system element, but also incur a change in the whole system topology.

It is important that the steady state operating equilibrium restored after the disturbance should be steady state acceptable. Otherwise protection systems could initiate new disturbances that in turn may lead to the instability of the system. To prevent this situation, acceptable operating conditions must be clearly defined for the power system.

Power system stability can be classified into the following three types: rotor angle, voltage and frequency stability. Each of these types can be classified also into a large disturbance or a small disturbance, short term or long term. The classification of power system stability is shown in Figure 1.1 [11].

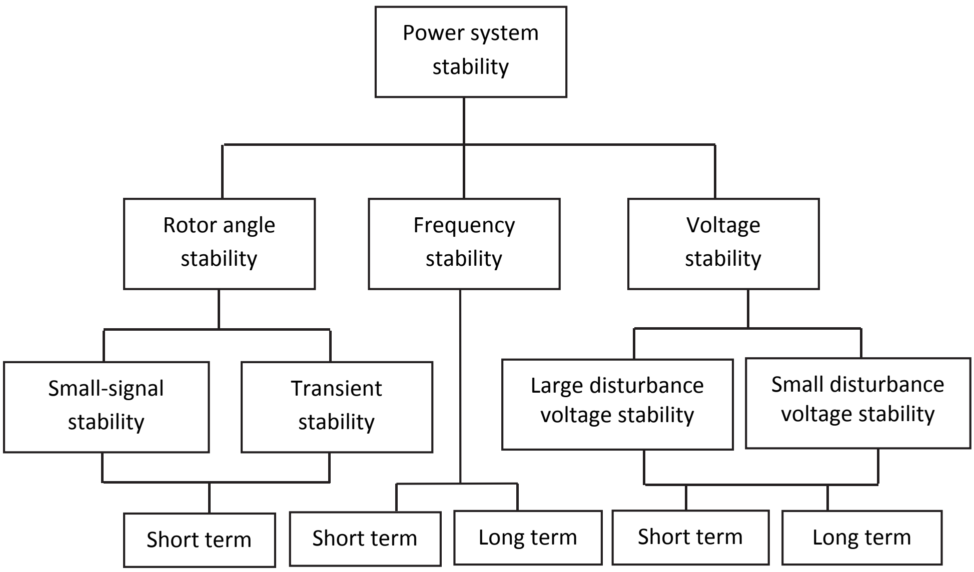

Figure 1.1 Classification of power system stability

1.2. Rotor angle stability

Rotor angle stability is the ability of interconnected generators to maintain synchronism between them after a disturbance occurred in the power system. In other words, rotor angle stability is the ability of interconnected generators of the system to restore the equilibrium between mechanical and electromagnetic torques on each rotor after a disturbance. If this equilibrium is disturbed in some generator after a disturbance in the system, it can lead to oscillations of the rotor angle. As a result, rotor runs at a higher or lower speed than it is required to generate voltage at system frequency. This in turn leads to large fluctuations in the generator power output, current and voltage. These fluctuations can cause the protection system of the generator to switch it off from the system. Because of disturbance in the system the synchronism can be lost between one machine and the rest of the system or between groups of the machines [11].

The change in the electromagnetic torque ΔT_e of a synchronous machine following a disturbance can be expressed [12]:

$$\Delta T_e = T_S \Delta\delta + T_D \Delta\omega \qquad (1.1)$$

where

$T_S \Delta\delta$ – synchronizing torque component,

$T_D \Delta\omega$ – damping torque component,

$\Delta\delta$ – rotor angle perturbation,

T_S – synchronizing torque coefficient,

$\Delta\omega$ – speed deviation,

T_D – damping torque coefficient.

System stability depends on the presence of both components of torque for each of the synchronous machines. Shortcomings of adequate synchronizing torque results in instability through an aperiodic drift in the rotor angle. However, shortcomings of adequate damping torque result in oscillatory instability [12].

Small signal stability

Small signal stability deals with the ability of the power system to regain synchronism after being subject to small disturbances. The reason of occurrence of small disturbances can be small variations in power generation or consumption, and such disturbances occur in the system constantly. These disturbances are considered to be sufficiently small that allows linearization of the system equations around an equilibrium point [11].

Small disturbances can cause two types of instability: non-oscillatory instability and oscillatory instability [12]. In case of non-oscillatory instability, rotor angle steady increases due to insufficient synchronizing torque. In case of oscillatory instability, the rotor angle oscillates with increasing magnitude due to insufficient damping torque.

Most commonly small-signal stability problems are associated with rotor angle oscillations. Depending on the extension of the involved area, these problems can be divided into local and global ones. Local problems are associated with rotor angle oscillations of a single generator or a single plant with respect to the rest of the system. These oscillations are called local plant mode oscillations and usually localized at the power plant or a small part of the system. Also, local problems may be associated with oscillations between the rotors of a few generators close to each other. These oscillations are called inter-machine or inter-plant mode oscillations. Global small-signal stability problems are associated with oscillations of a group of generators in one part of the system swinging against a group of generators in other parts. Such oscillations are called inter-area mode oscillations, and they are caused by two or more groups of closely coupled machines being interconnected by weak ties [13, 14].

Also, depending on the components involved, control mode oscillations and torsional mode oscillations are identified. Control mode oscillations are associated with generating units and other controls. Such oscillations may be caused by speed governors, poorly tuned exciters, HVDC converters and static var compensators. Torsional mode oscillations are associated with the turbine-generator shaft system rotational parts. Such oscillations may be caused by speed governors, excitation controls, HVDC controls and series capacitor compensated lines.

Transient stability

Transient stability is the ability of the power system to return to a stable condition and maintain its synchronism following a severe transient disturbance such as fault, switching on or off of large load, generator tripping. Since severe disturbance leads to large deviation of generator rotor angles, the power system cannot be approximated by a linear representation like in the case of small signal stability. Transient stability depends on the initial operating point, power system parameters and the severity of the disturbance. The tripping of generators losing synchronism and long-lasting voltage dips that disturb customers are not acceptable consequences of transient instability.

Modern fast excitation systems are usually acknowledged to be beneficial to transient stability following large impacts by driving the field to ceiling without delay. However, these fast excitation changes are not necessarily beneficial in damping the oscillations that follow the first swing, and they sometimes contribute to growing oscillations several seconds after the occurrence of a large disturbance [9].

In the transient stability the performance of the power system is studied when it is subjected to severe impacts. The concern is whether the system is able to maintain synchronism during and following these disturbances. The period of interest is relatively short (at most a few seconds), with the first swing being of primary importance. In this period the generator is suddenly subjected to an appreciable change in its output power causing its rotor to accelerate (or decelerate) at a rate large enough to threaten loss of synchronism. The important factors influencing the outcome are the machine behavior and the power network dynamic relations.

Most important synchronous machine parameters influencing transient stability are [15]:

a. the inertia constant,
b. the direct axis transient reactance,
c. the direct axis open circuit time constant,
d. the ability of the excitation system to hold the flux level of the synchronous machine and increase the output power during the transient.

1.3. Frequency stability

Frequency stability is the ability of a power system to restore equilibrium between the system generation and the load and, as a result, to re-establish steady frequency after a severe disturbance in the system. In contrast to rotor angle stability, when imbalance of active power occurs on a local level, frequency stability deals with imbalance of active power on a global level as this imbalance influences the frequency of the whole system.

In case of a small imbalance between the generation and the load, active power deficit is compensated by the energy stored in the rotating masses of generators and by an increase in the production of generation units, which are participating in frequency regulation. In case of a large imbalance, frequency instability may lead to sustained frequency swings that in turn lead to disconnection of generators and consumptions.

Frequency regulation is closely discussed in Chapter 5 of this thesis and frequency relationship with the turbine governor system is introduced in Chapter 4.

1.4. Voltage stability

Voltage stability is the ability of a power system to keep steady voltages at all buses in the system after a disturbance. Voltage stability always refers to the balance of reactive power in the system. This means that the produced reactive power should be equal to the consumed reactive power in every node of the system. To keep this balance, the injected reactive power should be such that the voltage in the node must be maintained to acceptable values. If the imbalance of the reactive power occurs in the system, it means that the injected reactive power differs from the desired injected reactive power needed to keep the desired voltage. In other words, voltage stable operating condition of the system is provided if the bus voltage magnitude increases as the reactive power injection at the same bus is increased. A system is voltage unstable if the bus voltage magnitude decreases as the reactive power injection at the same bus is increased. Large voltage instability may lead to a situation when the voltage is outside an acceptable range [9].

Since the reactive resistance of the system is much greater than the active one, reactive power cannot be easily transported within the system. For that reason the reactive power is more local quantity than the active power, and its imbalance often causes local problems that occur only in part of the system. Voltage decrease is usually associated with high load conditions, and vice versa, voltage increase is caused by low load conditions. Low and high voltage both may lead to voltage instability [16].

Generator automatic voltage regulators (AVR) are the most important means of voltage control in a power system. Under normal conditions the terminal voltage of generators is maintained constant. During the conditions of low system voltages, the reactive power demand on the generators may exceed their field current and/or armature current limits. When the reactive power output is limited, the terminal voltage is no longer maintained constant. A term also used in conjunction with voltage stability problems is voltage collapse. The term collapse may be used to signify a sudden catastrophic transition that is usually due to an instability occurring in a faster time-scale than the one considered. Voltage collapse may or may not be the final outcome of voltage instability [11].

2. Generator modelling

Any used model must be accurate for the results to be meaningful. In large systems, gathering accurate dynamic data is not a simple task. This is particularly true of the data for modelling the controls used in power systems. Data obtained from manufacturers may be based on the state of a control following commissioning, or it may be based on the state on the engineering design. Critical plants for a particular study need to be modeled in more detail and generators which are located further away may be modeled by simplified models. This chapter describes two types of generator models: a simplified model and a more complex generator model with generator controls.

The synchronous machine under concern is presumed to have three rotor windings:

- 1 field winding,
- 2 amortisseur or damper windings.

Six windings (three stators, one field and two damper) are magnetically coupled and the magnetic coupling between the winding is a function of the rotor position. The flux linking each winding is a function of the rotor position. The instantaneous terminal voltage U of any winding is in the form [17]:

$$U = \pm \sum \lambda \pm \sum ri \tag{2.1}$$

where

λ – the flux linkage,

r – the winding resistance,

i – the current.

Current is with positive direction of stator currents flowing out of the generator terminals. The notation $\pm\sum$ indicates the summation of all appropriate terms with due regard to signs. The expressions for the winding voltage are complicated because of the variation of λ with the rotor position.

A major simplification in the mathematical description of the synchronous machine can be gained if the variables are transformed. One of the transformations that can be used is called Parks's transformation. It specifies a new set of stator variables: currents, voltage or flux linkages in terms of the actual winding variables. Two stator electromagnetic fields, both moving at rotor speed, were determined by dismembering each stator phase current under steady state into two components: one in phase with the electromagnetic field and the other with the phase shifted by 90°. With the above, an air gap field with its maximum aligned to the rotor poles (d axis) can be constituted, while the other is aligned to the q axis (between poles) [18].

Park's transformation gives us [17, 19]:

$$i_d = \left(\frac{2}{3}\right)\left[i_a \cos(\Theta) + i_b \cos\left(\Theta - \frac{2\pi}{3}\right) + i_c \cos\left(\Theta - \frac{4\pi}{3}\right)\right] \tag{2.2}$$

$i_q = (\frac{2}{3})\left[i_a \sin(\Theta) + i_b \sin\left(\Theta - \frac{2\pi}{3}\right) + i_c \sin\left(\Theta - \frac{4\pi}{3}\right)\right]$

where

Θ [rad] – the angle between the phase current i_a and the current i_d,

i_a, i_b and i_c – the phase currents,

2.1. Classical model

A generator model is simplified by presuming that E'_q (or Ψ_{fd}) is constant over the study period. This presumption removes the only differential equation associated with the electrical characteristics of the machine. Also, the following approximations can be made to simplify the generator model [11]:

- to ignore transient saliency by assuming that direct axis transient reactance (x'_d) is equal to the quadrature axis transient reactance (x'_q)
- to assume that the flux linkage Ψ_{1q} (associated with the q-axis rotor circuit corresponding to x'_q) also remains constant.

With these assumptions, the voltage behind the transient impendence $R_a + jX'_d$ has a constant magnitude.

With the rotor flux linkage (ψ_{fd} and ψ_{1q}) constant, E'_q and E'_d are constant and the magnitude of E' is also constant. As the rotor speed changes, the d- and q-axes move with respect to any general reference coordinate system whose R-I axes rotate at synchronous speed, as shown in Figure 2.1 [11]. Thus, the components E'_R and E'_Ichange.

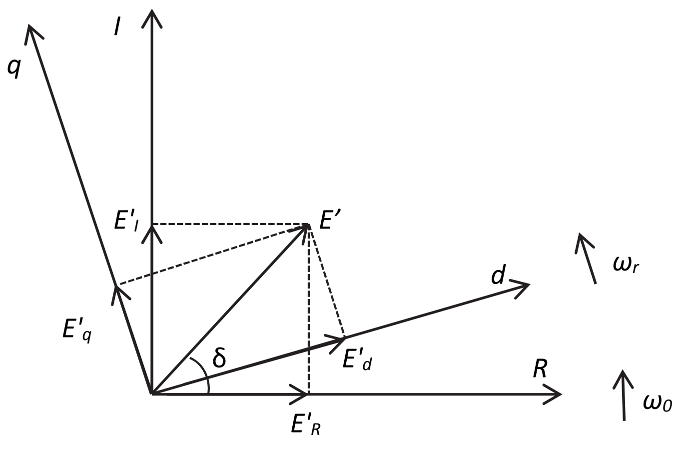

Figure 2.1. The R-I and d-q coordinated systems

The magnitude of E' can be defined by computing its pre-disturbance value.

$$\tilde{E}' = \tilde{E}_{t0} + (R_a + jX'_d)I_{t0} \quad (2.3)$$

Its magnitude is then assumed to remain constant over the study period. Usually R_a is neglected, because it is small.

With the components E'_q and E'_d each having a constant magnitude, E' will have constant orientation with respect to d- and q- axes, as the rotor speed changes. Therefore, the angle of E' can be used as a measure of the rotor angle with respect to synchronously rotating reference axes (R-I).

For a machine connected to an infinite bus through a transmission grid, the following s domain relations can be defined:

$$P_{e\Delta} = K_1\delta_\Delta + K_2E'_\Delta \quad (2.4)$$

$$E'_\Delta = \frac{K_3}{1+K_3\tau'_{d0}s}U_{F\Delta} - \frac{K_3K_4}{1+K_3\tau'_{d0}s}\delta_\Delta \quad (2.5)$$

where

K_1 – the change in electrical power for a change in the rotor angle with constant flux linkage in the direct axis,

K_2 – the change in electrical power for a change in the direct axis flux linkages with constant rotor angle.,

t'_{d0} – the direct axis open circuit time constant of the machine,

K_3 – an impedance factor,

K_4 – the demagnetizing effect of a change in the rotor angle (at steady state) [15].

Figure 2.2 [15] shows a simple linearized block diagram representation of a generator model.

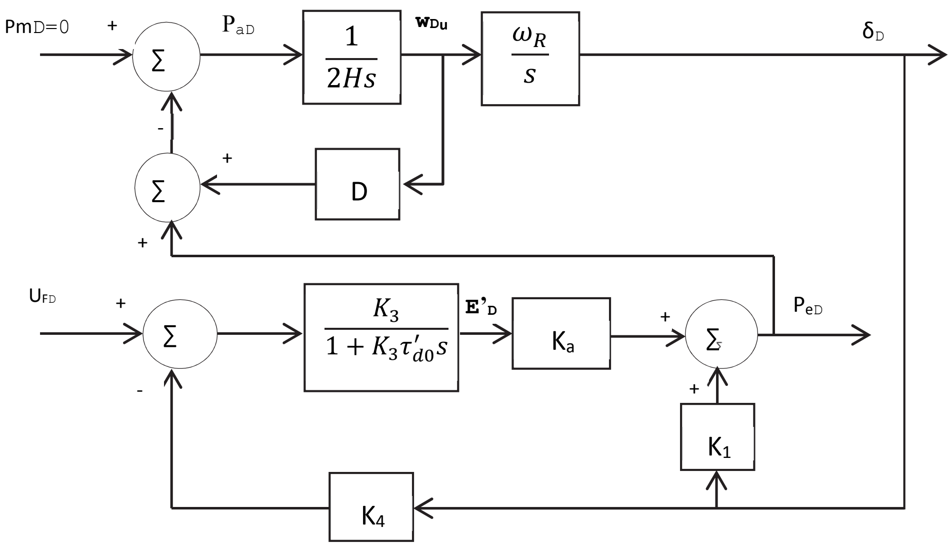

Figure 2.2 Simple linearized block diagram representation of a generator model

The constants *K1*, *K2*, and *K4* depend on the parameters of the parameters of the machine, the external network and the initial conditions. Note that *K1* is similar to the synchronizing power coefficient P_s used in the simpler machine model of constant voltage behind transient reactance [15].

$$P_{e\Delta} = \left(K_1 - \frac{K_2 K_3 K_4}{1+K_3 \tau'_{do} s}\right)\delta_\Delta + \frac{K_2 K_3}{1+K_3 \tau'_{do} s} U_{F\Delta} \quad (2.6)$$

For the case where U_{FD}=0,

$$P_{e\Delta} = \left(K_1 - \frac{K_2 K_3 K_4}{1+K_3 \tau'_{do} s}\right)\delta_\Delta \quad (2.7)$$

Substituting in the linearized swing equation:

$$\frac{2H}{\omega_R}\frac{d^2\delta_\Delta}{dt^2} + P_s \delta_\Delta = 0 \quad (2.8)$$

we obtain a new characteristic equation (with *D*=0):

$$\left[\frac{2H}{\omega_R} s^2 + \left(K_1 - \frac{K_2 K_3 K_4}{1+K_3 \tau'_{do} s}\right)\right]\delta_\Delta = 0 \quad (2.9)$$

or we have the third-order system

$$s^3 + \frac{1}{K_3 \tau'_{do}} s^2 + \frac{K_1 \omega_R}{2H} s + \frac{\omega_R}{2H}\frac{1}{K_3 \tau'_{do}}(K_1 - K_1 K_3 K_4) = 0 \quad (2.10)$$

Synchronously connected generators represented by classical generator models exhibit only electromechanical oscillations. Electromechanical oscillations are those associated with the tendency for the generators to remain in synchronism when interconnected. This model offers considerable computational simplicity; it allows the transient electrical performance of the machine to be represented by a simple voltage source of fixed magnitude behind an effective reactance. It is commonly referred to as the classical model used in early stability studies [11].

One of the most popular power system simulation and calculation software is Power System Simulator for Engineering (PSS/E). This software is also used by the Estonian TSO, therefore in this thesis models that can use PSS/E are proposed and investigated.

In the PSSE model library the classical model is called the constant internal voltage generator model (GENCLS) [19]. The model has three input signals: mechanical power, field voltage and voltage at the terminal bus. Also, the model has four output signals: source current, rotor angle, speed deviation and terminal voltage. The GENCLS model is defined by two constant parameters: inertia and damping constant. The GENCLS model has no input from the excitation system and from the power system stabilizer.

The GENCLS model suits in the conditions where generator data are not available and generators are further away from the investigated generators. In the stability studies of the Estonian power system, the GENCLS model can be used to model Russian and Belorussian system generators. However, Russian nuclear power plants and large thermal power plants located close to Estonian boarder should be modeled by using a detailed generator model, because their behavior is important in the stability studies.

List of the assumptions, which are made in classical model and brief comments of them [15]:

1. Neglecting the damping powers.
   Very large power system has relatively weak tie lines and is quite badly damped. It is important to account for the various components of the system damping in order to have a correct model that will accurately prognosticate power system dynamic performance.
2. Constant mechanical power.
   If the period of interest is more than a few seconds, it is incorrect to presume that the mechanical power will be constant. The turbine-governor characteristics and perhaps boiler characteristics should be considered in the analysis.
3. Flux linkage of the main field winding of a constant generator.
   This assumption is susceptible on two counts: the longer period that must now be considered and the speed of many modern voltage regulators. The longer period means that the change in the main field–winding flux may be appreciable and should be accounted for so that an adequate representation of the system voltage is realized. In addition, the voltage regulator response could have an important effect on a field-winding flux. It can be concluded that the constant voltage behind transient reactance could be totally incorrect.
4. Transient stability is decided in the first swing.
   As was mentioned in the introduction of this thesis, usually transient stability is decided in the first swing. However, in a large system with many machines numerous natural frequencies of oscillation occur. Because the capacities of most of the tie lines are comparatively small, as a result, some of these frequencies are quite low and frequencies of periods in the order of 5-6 are quite common. So it is possible that the worst swing may happen at an instant in time when the peaks of some of these nodes coincide. Therefore, it is necessary to study the transient for a period longer than one second.

It can be concluded from here that the classical model is inadequate for system stability analysis beyond the first swing. While the first swing is mainly an inertial response to a given accelerating torque, the classical model provides beneficial information concerning system response during that brief period.

2.2. Detailed model with generators controls

Next, focus will be on the influence of voltage and speed control equipment on the dynamic performance of the synchronous machine. Two simple cases of regulation will be considered: a simple voltage regulation with one time lag and a simple governor with one time lag.

Voltage regulation

Change in the field voltage (U_{FD}) is produced by changes on in either U_{REF} or U_t. If we assume that U_{REFD}=0 and the transducer have no time lags, U_{FD} depends only on U_{tD}, modified by the transfer function of the excitation system. To simplify the analysis, a rather simple model of the voltage regulator and the excitation system is assumed. This gives the following s domain relation between the change in the exciter voltage U_{FD} and the change in the synchronous machine terminal voltage U_{tD} [15]:

$$U_{F\Delta} = -\left[\frac{K_e}{1+\tau_e s}\right] U_{t\Delta} \tag{2.11}$$

where

K_e – voltage regulator gain

t_e – voltage regulator time constant

To use (2.11) a relation between U_{tD}, d_D and E'_D is needed. Such a relation is in the form:

$$U_{t\Delta} = K_5\delta_\Delta + K_6 E'_\Delta \tag{2.12}$$

where

$K_5 = \frac{U_{t\Delta}}{\delta_\Delta}]_{E'_\Delta}$ – change in the terminal voltage with a change in the rotor angle for the constant E'

$K_6 = \frac{U_{t\Delta}}{\delta_\Delta}]_{\delta_\Delta}$ – change in the terminal voltage with a change in E' for the constant d [15].

The generator block diagram with the voltage regulation added is shown in Figure 2.3 [15].

From (2.11) and (2.12):

$$U_{F\Delta} = -\left[\frac{K_e}{(1+\tau_e s)}\right](K_5\delta_\Delta + K_6 E'_\Delta) \tag{2.13}$$

Substituting in (2.05), we compute

$$E'_\Delta = \frac{K_3}{1+K_3\tau'_{d0}}\left[-\frac{K_e}{1+\tau_e s}(K_5\delta_\Delta + K_6 E'_\Delta)\right] - \frac{K_3K_4}{1+K_3\tau'_{d0}s}\delta_\Delta \tag{2.14}$$

or rearranging

$$E'_\Delta = \left[-\frac{K_4}{\tau'_{d0}}\frac{s+\left(\frac{1}{\tau_e}+\frac{K_5K_e}{K_4\tau_e}\right)}{s^2+s\left(\frac{1}{\tau_e}+\frac{1}{K_3\tau'_{d0}}\right)+\frac{1+K_3K_6K_e}{K_3\tau'_{d0}\tau_e}}\right]\delta_\Delta \tag{2.15}$$

from (2.04) and (2.15):

$$P_{e\Delta} = \left[K_1 - \frac{K_2K_4}{\tau'_{d0}}\frac{s+\left(\frac{1}{\tau_e}+\frac{K_5K_e}{K_4\tau_e}\right)}{s^2+s\left(\frac{1}{\tau_e}+\frac{1}{K_3\tau'_{d0}}\right)+\frac{1+K_3K_6K_e}{K_3\tau'_{d0}\tau_e}}\right]\delta_\Delta \tag{2.16}$$

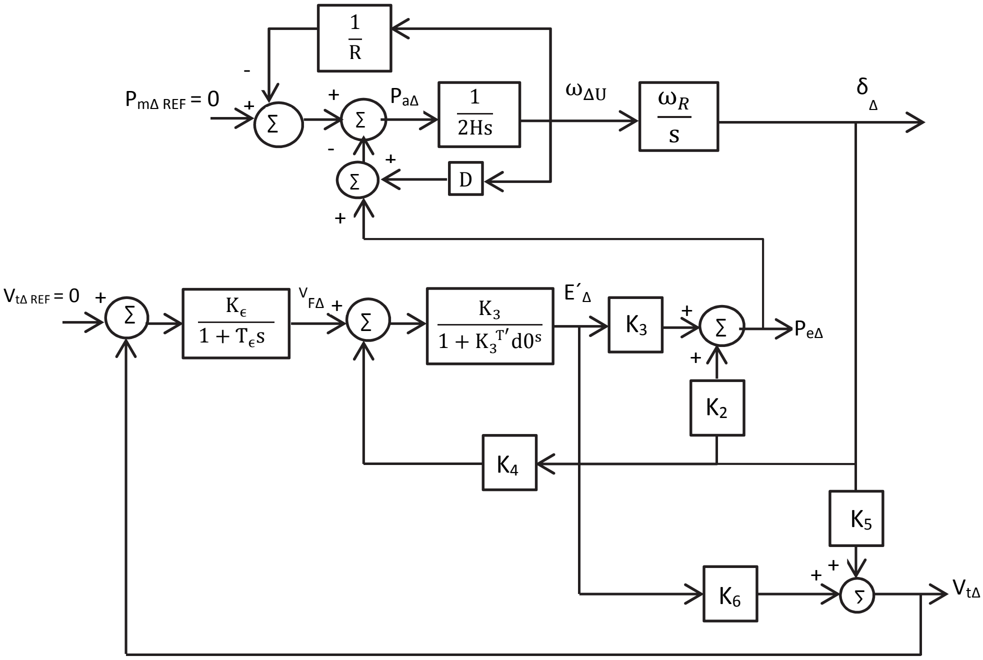

Figure 2.3 Generator block diagram with voltage regulation.

Substituting in the s domain the swing equation and rearranging, we obtain the following characteristic equation:

$$s^4 + s^3\left(\frac{1}{\tau_e} + \frac{1}{K_3\tau'_{d0}}\right) + s^2\left(\frac{1+K_3K_6K_e}{K_3\tau'_{d0}\tau_e} + \frac{K_1\omega_R}{2H}\right) + s\,\frac{\omega_R}{2H}\left(\frac{K_1}{\tau_e} + \frac{K_1}{K_3\tau'_{d0}} + \frac{K_2K_4}{\tau'_{d0}}\right)$$
$$+ \frac{\omega_R}{2H}\left[\frac{K_1(1+K_3K_6K_e)}{K_3\tau'_{d0}\tau_e} - \frac{K_2K_4}{\tau'_{d0}}\left(\frac{1}{\tau_e} + \frac{K_5K_e}{K_4\tau_e}\right)\right] = 0 \qquad (2.17)$$

Equation (2.17) is of the form [14]:

$$s^4 + \alpha_3 s^3 + \alpha_2 s^2 + \alpha_1 s + \alpha_0 = 0 \qquad (2.18)$$

Speed regulation

Change in the speed w or in the load or speed reference [governor speed changer (GSC)] produces a change in the mechanical torque T_m. The amount of change in T_m depends upon the speed droop and upon the transfer function of the governor and the energy source [15].

For the model under consideration it is assumed that $GSC_D = 0$ and that the combined effects of the turbine and the speed governor system are such that the change in the mechanical power in per unit is in the form:

$$P_{m\Delta} = -\left[\frac{K_g}{(1+\tau_g s)}\right]\frac{\omega_\Delta}{\omega_R} \qquad (2.19)$$

where

K_g – gain constant (1/R),

τ_g – governor time constant.

The system block diagram with the governor regulation is shown in Figure 2.4 [15].

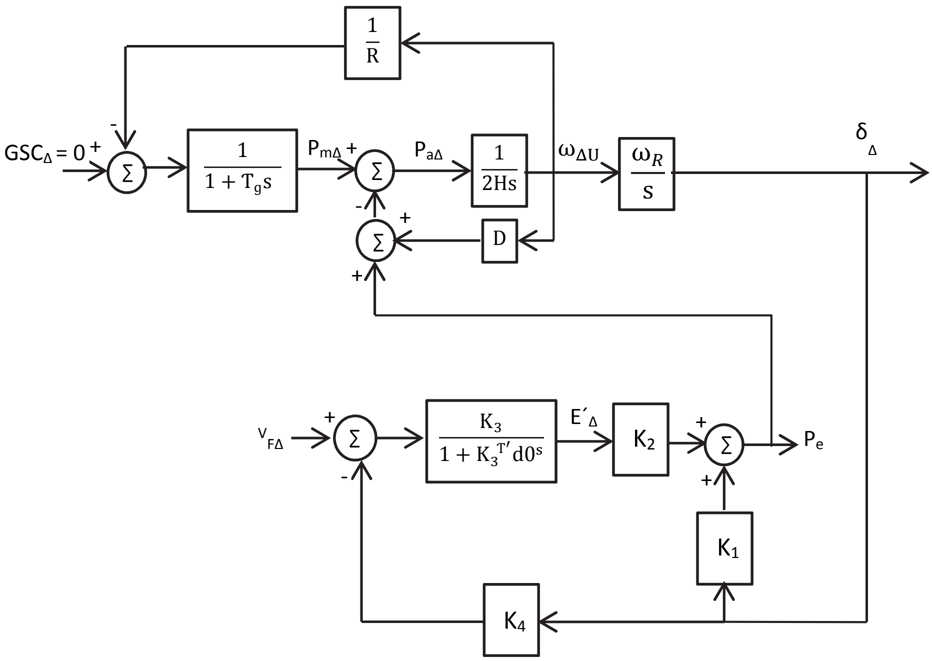

Figure 2.4 Block diagram of a generator with the governor speed regulation

Then the linearized swing equation in the s domain with w_R (rad/s) is as follows:

$$\left(\frac{2H}{\omega_R}\right) s^2 \delta_\Delta(s) = -\left[\frac{K_g}{1+\tau_g s}\right] \frac{s\delta_\Delta(s)}{\omega_R} - P_{e\Delta}(s) \qquad (2.20)$$

The order of this equation will depend upon the expression used for P_{eD}(s). If we assume the simplest model possible, P_{eD}(s) = P_s d_D(s) the characteristic equation of the system is given by:

$$\left(\frac{2H}{\omega_R}\right) s^2 + \left(\frac{K_g}{1+\tau_g s}\right) s + P_s = 0 \qquad (2.21)$$

or

$$s^3 \left(\frac{2H\tau_g}{\omega_R}\right) + s^3 \left(\frac{2H}{\omega_R}\right) + \left(K_g + P_s \tau_g\right) s + P_s = 0 \qquad (2.22)$$

The system is now of third order [15].

If another model is used for P_{eD}(s) such as the model given by (2.04) and (2.05), the system becomes of fourth order. Its dynamic response will change. Information on stability can be obtained from the roots of the characteristic equation or from examining the eigenvalues of its characteristic matrix.

If both the speed governor and the voltage regulation are added simultaneously, as is usually the case, the system becomes fifth order, as shown in Figure 2.5 [15].

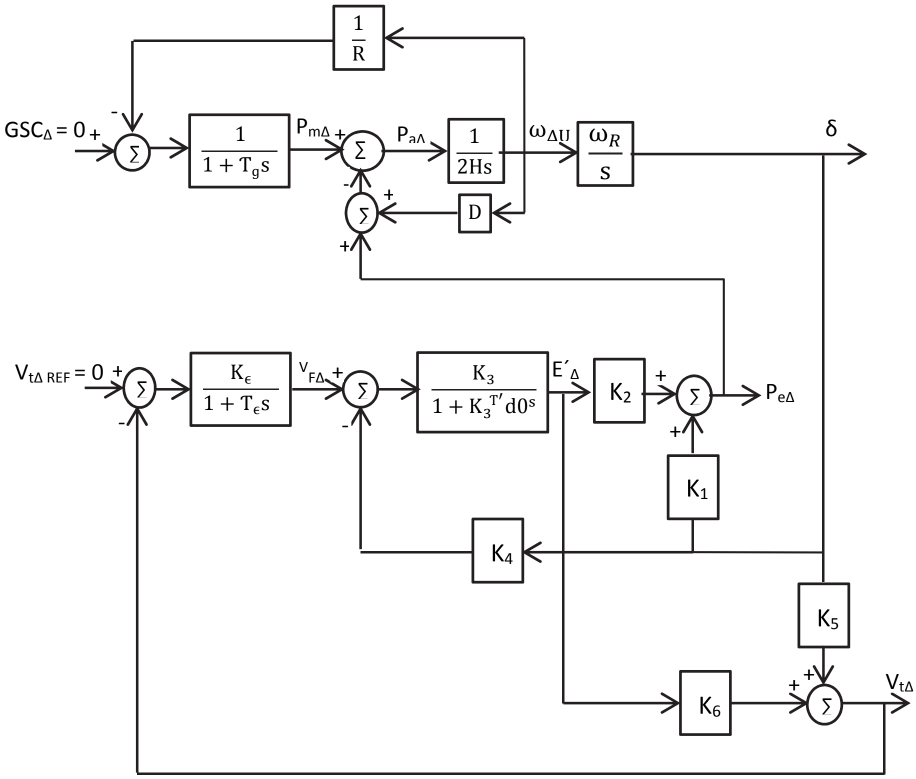

Figure 2.5 Block diagram of a generator with a governor and a voltage regulator

For modelling steam turbine generators in the PSSE model, Round Rotor Generator Model, Quadratic Saturation (with abbreviation GENROU) can be used. Similarly to the GENCLS model, the GENROU model has three input signals: mechanical power, field voltage and voltage at terminal bus and similarly four output signals: source current, rotor angle, speed deviation and terminal voltage. The GENCLS model has only two constant parameters: inertia and damping constant [19]. GENROU has 15 constant parameters, the list of GENROU parameters is shown in Table 2.1 with recommended settings for the Eesti Power Plant and for the Balti Power Plant units. The GENROU model data is given for power plant units with pulverized fired (PF) boilers and for power plant units with circulating fluidized bed (CFB) boilers.

Table 2.1. Generator data for Balti power plant and Eesti power plant units with PF boilers and CFB boilers units

Abbreviation	Name	Unit	Recommended value for PF boiler unit	Recommended value for CFB boiler unit
X_d	Direct axis synchronous reactance	p.u	1.88; 2.1[1]	2.33
X_q	Quadrature axis synchronous reactance	p.u	1.65	1.65
X'd	Direct axis transient reactance	p.u	0.275; 0.29[2]	0.29
X'q	Quadrature axis transient reactance	p.u	0.5	0.5
X''_d	Direct axis sub transient reactance	p.u	0.2	0.2
X''_q	Quadrature axis sub transient reactance	p.u	0.2	0.2
X_l	Leakage reactance	p.u	0.15	0.17
D	Damping constant	p.u	0	0
H	Inertia	MWs/ MVA	4.2	4.2
T'do	Direct axis transient open circuit time constant	sec	8.48	8.48
T'qo	Direct axis transient open circuit time constant	sec	0.8	0.8
T"do	Direct axis sub transient open	sec	0.17	0.17

[1] 1.88 - for the Eesti Power Plant boilers and 2.1 for the Balti Power Plant boilers
[2] 0.275 - for the Eesti Power Plant boilers and 0.29 for the Balti Power Plant boilers

	circuit time constant			
T"qo	Direct axis sub transient open circuit time constant	sec	0.15	0.15
S(1.0)	Saturation factor	p.u	0.1	0.1
S(1.2)]	Saturation factor	p.u	0.4	0.4

The GENROU model is used in PSSE to model steam turbines with generator controls. Excitation system input in this model is EFD (field voltage) and governor system input is mechanical power (PMECH).

2.3. Conclusion

As was explained above, the classical generator model is quite inaccurate. Therefore, it is recommended to use a generator model with all generator controls for the stability studies of the Estonian power system. The GENROU model can be used to model all the Balti and the Eesti Power Plant units.

The GENROU model is detailed and requires much data and in order the results to be meaningful the data must be accurate. If necessary, generator testing may be needed to measure the required data. Still, generator testing may damage the generator and will place the turbine and the generator under considerable stress. Also, generator testing is quite expensive. Table 2.1 presents the recommended setting of the generator model according to parameter measurements done in the past.

To model Latvian and Lithuanian hydro power plants in PSSE, the generator model GENSAL (salient pole generator model with quadratic saturation on d-axis) can be used. To model Latvian, Lithuanian, Belorussian and Russian large thermal and nuclear power plant units, also the GENROU model can be used.

3. Excitation system modelling

The excitation system has the following main functions [17]:

- to supply direct current to the generator field windings,
- to regulate the generator terminal voltage,
- to control the reactive power flow between the generator and the power grid,
- to improve the stability of the power system,
- to provide limiting and control functions to the generator.

There are two types of excitation systems: independent and dependent system [21] according to the power source. In independent excitation systems for a power source part of turbine mechanical power is used. Hence, the exciter is independent of the grid and exciter performance is not directly influenced by grid operating parameters. In that case the exciter is usually:

- a DC generator,
- an AC generator (high frequency or in normal frequency) with a rectifier

In a dependent excitation system, the power comes from the generator itself or from the grid. In case of dependent excitation system the exciter is usually:

- a DC generator
- a rectifier.

Until 1960, a DC generator placed in the same shaft with the main generator was used as an exciter. The maximum power of the DC generator was 0.5 MW, while the rotation speed was 3000 turns per minute. This exciter provides excitation only for turbo generation with a maximum power of about 100 – 150 MW. Decreasing exciter rotation speed enables the power of the exciter to be increased up to 3 MW, so this exciter can provide power to the generator with a maximum power of up to 300 MW. Nowadays, DC generators are used only as excitation generators with power up to 100 MW or as a reserve excitation power source. High frequency exciter with non-controllable semiconductor rectifier excitation systems are used in generators with power 150 – 500 MW. Dependent excitation systems are commonly using controllable rectifiers that receive power from the power grid or from the generator itself [22]. Advantages of the dependent system are simplicity and low costs. The main disadvantage is that excitation supply voltage and thereby excitation current depend directly on the generator output voltage [23].

In the Eesti Power Plant and the Balti Power Plant, generation units with CFB boilers use the static excitation system, which is a dependent system, excitation power coming from the generator bus-bar. Also in new Auvere Power Plant unit generator is used static excitation system. In the generation units with PF boilers the high frequency AC machine excitation system is used, which is an independent system, since the excitation power comes from the AC generator placed on the same shaft with the main generator.

The basic requirement is that the excitation system supplies and automatically adjusts the field current of the synchronous generator to maintain the terminal voltage as the output varies within the continuous capability of the generator. In addition, the excitation system must be able to respond to transient disturbances with field forcing consistent with the generator instantaneous and short term capabilities. Excitation systems are composed of a terminal voltage transducer, an automatic voltage regulator, an exciter and compensators. Sometimes, it also includes limitation and protection circuits, and a power system stabilizer, see Figure 3.1 [24].

Terminal voltage transducer conditions the terminal voltage to introduce it to the automatic voltage regulator (AVR). The AVR processes and amplifies the input signal to an appropriate level and form in order to control the exciter, which provides the power of direct current to the field winding of the generator. Protective and limiting systems include a wide number of control and protection circuits that guarantee the operation within the capability limits of the exciter and the generator. The power system stabilizer introduces damping to mitigate the oscillations of the power system. Additional compensators could be introduced to deal with load transients, line drops, and reactive current.

Several bachelor's and master's theses about excitation systems have also been written at Tallinn University of Technology [25-27].

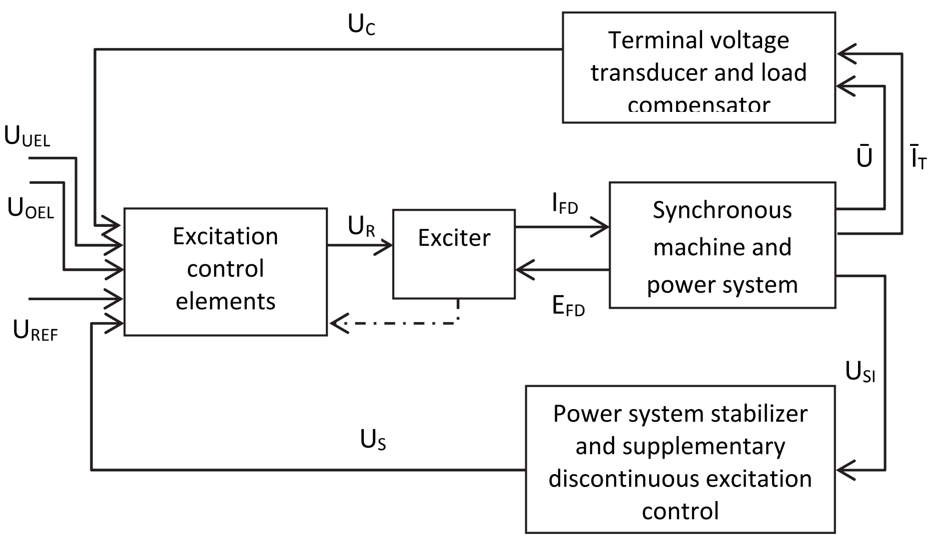

Figure 3.1 General block diagram for a synchronous machine excitation control system

The description of the excitation system signals depicted in Figure 3.1 contains the following:

E_{FD} – Exciter output voltage or synchronous machine field voltage

I_{FD} – Exciter output current or synchronous machine field current
$\bar{I}_T$ – Synchronous machine terminal current phasor
U_C – Output of terminal voltage transducer and load compensation elements
U_{OEL} – Overexcitation limiter output
U_R – Voltage regulator output
Us – Power system stabilizer output
U_{SI} – Power system stabilizer input
U_{REF} – Voltage regulator reference voltage
$\bar{U}_T$ – Synchronous machine terminal voltage phasor
V_{UEL} – Underexcitation limiter output

3.1. AC machine excitation system

This section proposes an excitation model for the AC machine excitation system used in the Balti and the Eesti Power Plant. The exciter type used is ВГТ-2700-500 and the regulator type is ЭПА-325. It is an old type of a Soviet-made excitation system. In this type of the excitation system the exciter is a high frequency (500 Hz) induction AC generator placed in the same shaft with the main generator. In the Soviet Union the type of excitation systems commonly used for power plants depended on the performance that would not be critical for system stability provision in the power system because of its inefficiency in terms of the dynamical stability of the system. In the Soviet Union fast acting excitation systems at the beginning were used in large hydro power plants and later also in large thermal power plants [28].

The principal scheme of a high frequency exciter excitation system is presented in PAPER I Figure 5.

Automatic voltage regulator

Automatic voltage regulator (AVR) has two electromagnetic magnifiers connected in series. Electromagnetic magnifiers have a ferromagnetic core the induction of which has the following relation [29]:

$$L = \frac{\omega^2 s\mu}{l} \qquad (3.1)$$

where
w – number of spins,
μ – wire magnetic permeability,
s – wire cross-section,
l – length of wire.

One electromagnetic magnifier is used to lead the exciter forcing winding and another is used to lead the exciter main winding. Both magnifiers have similar structure with three leading windings carrying out the following functions [30]:

- Excitation forcing limiter;
- Magnifier core for additional pre-magnetization;
- Flexible feedback that receives its power from a stabilizing transformer.

The exciter is controlled by magnifiers and therefore the inherent time constant of the excitation system is rather large. Therefore, these excitation systems are called slow response excitation systems (P-system). This type of AVR is commonly used with a high frequency exciter.

A simplified block diagram of AVR elements is shown in Figure 3.2 [28].

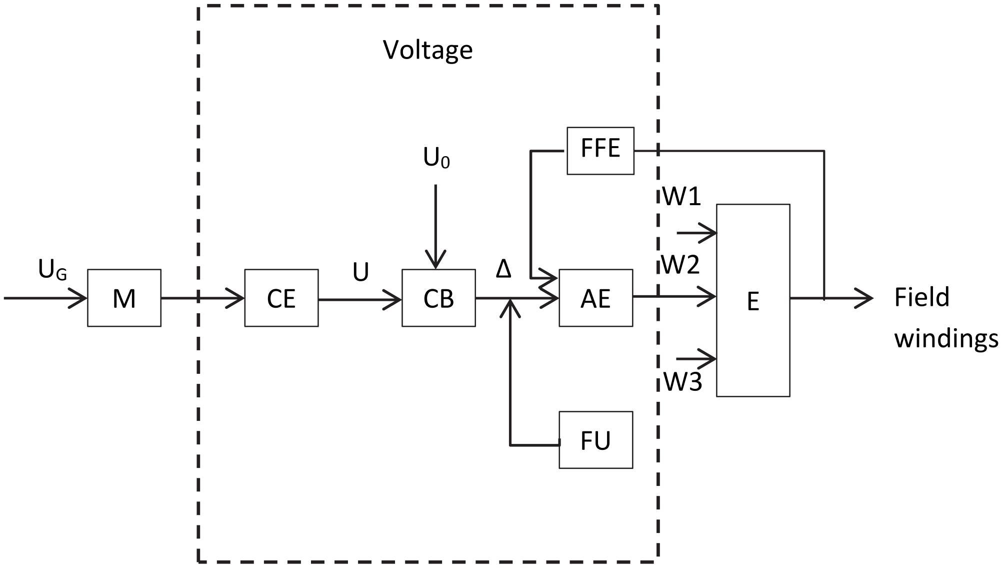

Figure 3.2 AVR block diagram

where
ME – measuring element,
CE – converting element,
CB – compensation block,
AE – amplification element,
FFE – flexible feedback element,
FU – forcing unit,
E – exciter,
U_G – generator voltage.

The exciter has three windings [30]:

W1 is used as the main excitation winding and it is connected serially with the generator rotor winding.

W2 is used for the excitation forcing system.

W3 is used to give additional excitation while the exciter is over excited.

Voltage regulator input signal is the generator voltage (U_G) from the generator bus-bar. First, generator voltage is going to the measuring element (ME), the voltage transformer. Voltage that is proportional to the ingoing Ug, is going to the converting element (CE), where it is filtered and directed. From there it moves to the comparison block (CB), where it is compared with the reference voltage (U_0). The difference ($DU=U_0 - U$) is amplified in the amplification element and moves to the exciter winding W2. The aim of the described regulation channel is to hold the generator U_g in compliance with the reference voltage U_o.

If $U_G=U_0$, the voltage from the comparison block is equal to 0 and the voltage regulator is not changing the exciter voltage, which in this case is regulated only by the exciter winding W1. If U_G is decreasing, then U is positive and as a result will change the current in the exciter winding W2, which will increase the magnetic flux in the exciter and increase current in the generator field winding and as a result, U_G will also increase. If U_G is increasing and as a result, DU is negative, the magnetic flux in the exciter is decreasing and U_G is decreasing also. This voltage regulation is working by using hard voltage feedback and it is sometimes called a static response system. If the static response system is not working, the generator is changing its regime, because in that case DU is 0, so the regulator is not regulating U_G in that case.

Stabilization channel consists of a flexible feedback element which gives additional input to the amplification element. This channel is acting only during the transient process, because during steady state the flexible feedback element output is equal to 0. Therefore, the stabilization channel is not influencing static generator characteristics.

Forcing unit (FU) consists of two elements: the relay of minimal voltage and the amplifier. When the forcing unit is working, the generator voltage U_G decreases from the reference voltage U_0 about 8 – 20%. Input from the forcing unit goes to the exciter winding W3, which is increasing the sum of excitation currents up to maximum. The forcing unit is working only during faults or other major emergencies in the grid. Thus, the forcing unit is not influencing generator's static characteristics. Therefore, it helps to sustain dynamic stability [28, 30, 31].

AC machine excitation system has installed additional equipment, which was not installed when the AC machine excitation system was put into operation. This is the transistor amplifier БСС – 2, in Russian literature it is called Блок стабилизации системы, system stabilizing block. However, БСС – 2 does not have the same functionality as the power system stabilizer (PSS). The main function of PSS is to damp oscillations, which occur between the generator and the power system. Generally, PSS input signals are shaft speed, terminal voltage and power [11], while БСС – 2 input is the generator bus-bar voltage and its main function is to provide additional faster voltage regulation.

This type of AC machine excitation systems has no standard model in the PSS/E library. PSS/E software has supplementary software called Graphical

Model builder (GMB), which allows modelling of excitation and governor systems by block diagrams of automation. AC machine excitation system block diagram of automation is presented in Figure 3.3. It is proposed on the basis of litrature [22, 28, 29] and it is presented in the form which can be used in GMB. In PAPER I discusses AC machine excitation system modelling in more detail.

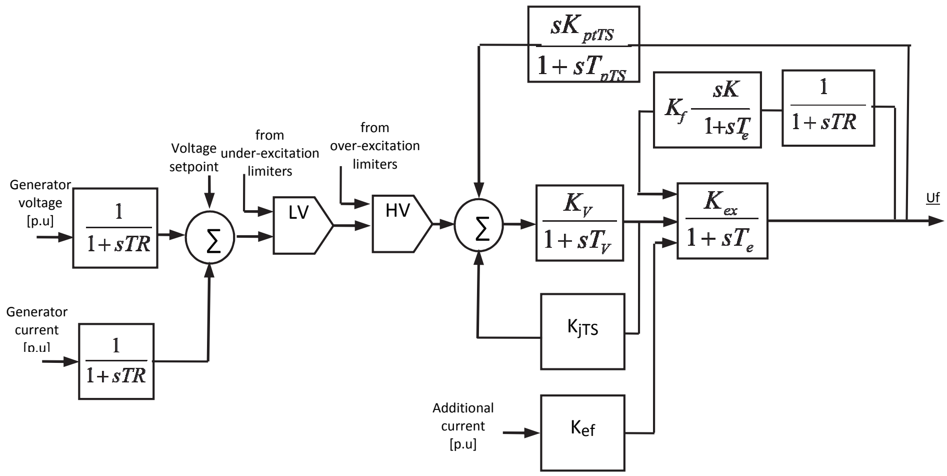

Figure 3.3 Block diagram of automation of a high frequency AC machine excitation system.

Designations in Figure 3.3 are as follows:
TR – measuring filter time constant,
K_f – amplification factor of winding W1,
K – amplification factor,
K_{pTS} – amplification factor of flexible feedback,
T_{pTS} – time constant of flexible feedback,
T_c – gate control unit and converter time constant,
K_v – amplification factor of an amplifier,
T_v – amplifier time constant,
K_{ex} – amplification factor of an exciter,
T_e – exciter time constant,
K_{jTS} – amplification factor of rigid feedback,
K_{ef} – exciter forcing factor.

Table 3.1 shows the parameters and recommended settings of the high frequency AC machine excitation system model [28, 31].

Table 3.1. High frequency AC machine excitation system parameters and recommended setting.

Abbreviation	Name	Unit	Recommended settings
TR	Measuring filter time constant	s	0.02
K_f	Amplification factor of winding W1	p.u.	1.654
K	Amplification factor	s	0.846
K_{pTS}	Amplification factor of flexible feedback	p.u.	0.02
T_{pTS}	Time constant of flexible feedback	s	0.2
T_c	Gate control unit and converter time constant	s.	0.004
K_v	Amplification factor of amplifier	p.u.	18.66
T_v	Amplifier time constant	s	0.16
K_{ex}	Amplification factor of exciter	p.u.	5.36
T_e	Exciter time constant	s	0.321
K_{jTS}	Amplification factor of rigid feedback	p.u.	- 0.054
K_{ef}	Exciter forcing factor	p.u.	0.8

3.2. Static excitation system

All the components in these systems are static or stationary. Static rectifiers, controlled or uncontrolled, supply the excitation current directly to the field of the main synchronous generator through slip rings. The supply of power to the rectifiers is from the main generator (or the station auxiliary bus) through a transformer to step down the voltage to an appropriate level, or in some cases from auxiliary windings in the generator [32].

Static excitation system UNITROL 5000 is used in one 253 MVA generator in the Balti Power Plant and in one 253 MVA machine in the Eesti Power Plant. Static excitation system UNITROL5000 has the following functions [33]:

1. Voltage regulator with a PID filter (AUTO operating mode);
2. Field current regulator with a PI filter (MAN operating mode);
3. Reactive load and/or active load droop/compensation;
4. Limiters for:
    - maximum and minimum field current
    - maximum stator current (lead/lag)
    - P/Q under excitation
    - voltage-per-hertz characteristics
5. Power factor/reactive load regulation

6. Power system stabilizer (PSS)
   - conventional in accordance with IEEE-PSS2A
   - adaptive power system stabilizer
   - multiband power system stabilizer

The excitation power is supplied through a transformer from the power station auxiliary bus, and it is regulated by a controlled rectifier. This type of excitation system is also commonly known as a bus-fed or transformer-fed static system. This excitation system scheme is presented in PAPER I in Figure 2.

Static excitation system has a small inherent time constant. As was mentioned above, the static excitation system is a dependent system, hence, the maximum exciter output voltage (ceiling voltage) is dependent on the input AC voltage. During a system fault, which causes depressed generator terminal voltage, the available exciter ceiling voltage is reduced. This limitation of the excitation system is compensated by its virtually instantaneous response and high post-fault field-forcing capability. For generators connected to large power systems such excitation systems perform satisfactorily [11].

The automation block diagram of UNITROL 5000 excitation system is shown in PAPER I, Figure 3. Table 3.2 shows UNITROL 5000 model parameters and default settings [33].

Table 3.2. Characteristics and parameters of the UNITROL 5000 exciter control system

Abbreviation	Name	Unit	Setting range	Default setting
TR	Measuring filter time constant	s	0.02	0.02
Ts	Gate control unit and converter time constant	s	0.004	0.004
KIR	Reactive power compensation factor	p.u.	-0.2…+0.2	0.0
KIA	Active power compensation factor	p.u.	-0.2…+0.2	0.0
KR	Steady state gain	p.u.	10…1000	500
TB1	Controller first lag time constant	s	TB1 ≥ TC2	12.5
TB2	Controller second lag time constant	s	0 < TB2 ≤ TC2	0.008
TC1	Controller first lead time constant	s	0.01…10	2
TC2	Controller second lead time constant	s	0.001…2	0.025
Up+	AVR output positive ceiling value	p.u.	Fixed	10.0
Up-	AVR output negative ceiling value	p.u.	Fixed	-0.85 * Up+

In PSS-E UNITROL 5000 can be modeled by using PSS-E standard model IEEE Proposed Type ST5B Excitation System (with abbreviation URST5T). Another way is to model UNITROL 5000 block diagram in PSS/E supplementary software GMB.

3.3. Power system stabilizer

As was mentioned above, the static excitation system UNITROL 5000 has one additional function, as compared to the AC machine excitation system, the power system stabilizer (PSS). PSS uses additional stabilizing signals to control the excitation system so as to enhance power system dynamic performance. Power system dynamic performance is improved by the damping of system oscillations. This is an efficient method to increase small-signal stability performance [11]. Basically, they act via the generator excitation system such that a component of electrical torque proportional to speed change is generated (an addition to the damping torque). The action of a PSS is to extend the angular stability limits of a power system by providing additional damping to the oscillation of synchronous machine rotors through the generator excitation. This damping is provided by an electric torque applied to the rotor that is in phase with the speed variation. However, an efficient stabilizer produces a damping torque over a wide range of input frequencies. Stabilizers that have lower efficiency may only produce a damping torque over a small frequency range, which can cause problems when the system changes lead to changes in the system oscillatory modes [11, 34].

PSS are one of the most cost-effective electromechanical damping controls, because the power amplification required is embodied in the generator. In some cases problems with PSS installation and commissioning have made TSO wary of PSS effect on the power system performance, which may as a result lead to their removal of service if oscillations are surveyed. The problem of PSS design is to define the parameters of the PSS so that the damping of the power system electromechanical modes is increased. This must be done without adverse effects on other oscillatory modes, such as those associated with the exciters or the shaft torsional oscillations. The stabilizer must also be designed so that it has no adverse effects on a system recovery from a severe fault [34].

UNITROL5000 PSS automation block diagram is presented in PAPER I, Figure 4. UNITROL 5000 PSS model parameters and default settings are given in Table 3.3 [33].

Table 3.3. Parameters and default settings of the UNITROL5000 power system stabilizers

Abbreviation	Name	Unit	Setting range	Default setting
TW1,TW2	Wash out time constants	s	01…30	TW1=2; TW2=2
TW3,TW4	Wash out time constants	s	01…30	TW3=2; TW4= not used
Ks1	PSS gain factor	p.u.	0.1…50.0	5
Ks2	Compensation factor for calculation of integral of electric power	p.u.	0.01…5.0	0.2
Ks3	Signal matching factor	p.u.	0.01…5.0	1.0
T1,T3	Lead time constants of conditioning network	s	0.01…2.5	T1=0.2; T3=0.36
T2,T4	Lag time constants of conditioning network	s	0.01…2.5	T2=0.04; T4=0.12
T7	Time constant for integral of electric power calculation	s	0.002…30	2
T8	Ramp tracing filter time constant	s	0.0…2.5	2
T9	Ramp tracing filter time constant	s	0.0…2.5	0.1
M	Ramp tracing filter degree	-	2…5	5
N	Ramp tracing filter degree	-	1…4	1
USTmax	Upper limit of stabilizing signal	p.u.	0.0…3.277	0.1
USTmin	Lower limit of stabilizing signal	p.u.	-USTmax	-USTmax

In PSS-E UNITROL 5000 power system stabilizer can be modeled by using PSS-E standard model IEEE Dual-Input Stabilizer Model (with abbreviation PSS2A). Another way is to model UNITROL 5000 power system stabilizer block diagram in PSS/E supplementary software GMB.

Soviet-made AC machine excitation systems have no power system stabilizer function. The AC machine excitation system has a forcing unit, which helps to keep the power system voltage in the acceptable range, but provides no help with damping of electromechanical oscillations.

3.4. Conclusion

As mentioned above, the AC machine excitation systems currently used in the Balti and the Eesti Power Plant are not effective for dynamic stability provision. Therefore, dynamic stability of the Estonian power system can be improved by replacing existing AC machine excitation systems with modern static excitation systems, which may appear necessary as the Estonian power system has undergone significant changes since the AC machine excitation systems were introduced in power plants.

The most important changes include:

1) 1000 MW transmission capacity between Estonian and Finnish power systems. In some cases it is possible that all or a large part of consumption in the Estonian power system is covered by Finnish energy. This would mean that most of the units in the Balti and the Eesti Power Plant will be switched off in the summer time. As a result, the importance of single unit dynamic stability provision will rise.
2) Changing power market in all three Baltic countries. The number of working generation units may change quite significantly in a relatively short period of time according to the day-ahead power market results. Consequently, the importance of single unit dynamic stability provision will rise.
3) Closure of the Ignalina NPP. The first and the second nuclear reactor of the Ignalina NPP were closed in December 2004, and in December 2009, respectively. As a result, the Lithuanian power system turned from an energy exporter into an energy importer. The situation where Lithuanian and Latvian power system imports are mostly covered by Russian exports would make Lithuanian and Latvian support for dynamic stability weaker. As a result, the importance of dynamic stability provision of Estonian power plants will rise.
4) Most of the Balti Power Plant units are already closed and some of the Eesti Power Plant units are going to work only for a limited time in future. 9 out of Balti Power Plant’s 12 units have already been closed down. 2 out of the 3 units at the plant, which are currently working, will also be closed in the near future. 3 out of 8 units of the Eesti Power Plant will be working for a limited time 2016-2023, not to exceed 17500 hours per unit. As a result, the importance of single unit dynamic stability provision will rise.

All these changes influence dynamic stability and should be further investigated. If the future research results confirm such necessity, the replacement of the AC machine excitation systems used at the units of the Eesti power plant with a new static excitation system should be considered.

Recommended excitation system settings need verification. Excitation system testing and parameter measurements may be needed in order to verify excitation system settings. AC machine excitation system settings in Table 3.1 are based on the literature [28, 31]. Therefore, setting verification is needed. Actual settings of the UNITROL5000 excitation system must be acquired from the Balti and Eesti Power Plant.

4. Governor system modelling

The frequency of a system is dependent on the active power balance and as a change in the active power demand at one point is reflected throughout the system by a change in the frequency. Because there are many generators supplying power into the system, some means must be provided to allocate changes in demand to the generators. A speed governor on each generating unit provides the automatic speed control function.

The basic concepts of speed governing are best illustrated by considering an isolated generating unit supplying a local load as shown in Figure 4.1 [11].

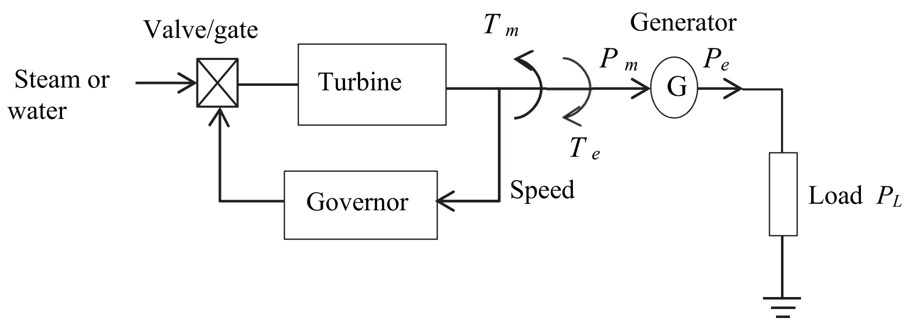

Figure 4.1 Generator supplying isolated load

where
T_m – mechanical torque,
T_e – electrical torque,
P_m – mechanical power,
P_e – electrical power,
P_L – load power.

When there is a load change, it is reflected immediately as a change in the electrical torque output T_e of the generator. This causes a mismatch between the mechanical torque T_m and the electrical torque T_e which in turn results in speed variations as determined by the equation of motion. The following transfer function represents the relationship between the rotor speed as a function of the electrical and mechanical torques, as shown in Figure 4.2 [11].

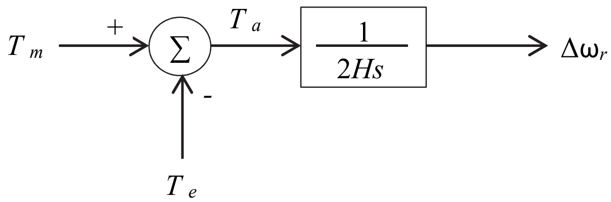

Figure 4.2 Transfer function relating speed and torques

where
s – Laplace operator,
T_m – mechanical torque,
T_e – electrical torque,
T_a – accelerating torque,
H – inertia constant,
$\Delta\omega_r$ – rotor speed deviation.

The relationship above can be expressed in terms of mechanical and electrical power instead of torque. The relationship between the power *P* and the torque *T* is given by

$$P = \omega_r T \quad (4.1)$$

By considering a small deviation (denoted by prefix Δ) from initial values (denoted by subscript 0), we can write:

$$P = P_0 + \Delta P \quad (4.2)$$

$$T = T_0 + \Delta T \quad (4.3)$$

$$\omega_r = w_0 + \Delta w_r \quad (4.4)$$

From Equation (4.1):

$$P_0 + \Delta P = (\omega_0 + \Delta\omega_r)(T_0 + \Delta T) \quad (4.5)$$

The relationship between the perturbed values, with higher-order terms neglected, is given by

$$\Delta P = \omega_0 \Delta T + T_0 \Delta\omega_r \quad (4.6)$$

Therefore,

$$\Delta P_m - \Delta P_e = \omega_0(\Delta T_m - \Delta T_e) + (T_{m0} - T_{e0})\Delta\omega_r \quad (4.7)$$

Since, in the steady state, electrical and mechanical torques are equal, $T_{m0} = T_{eo}$. With speed expressed in pu, $\omega_0 = 1$. Hence,

$$\Delta P_m - \Delta P_e = \Delta T_m - \Delta T_e \quad (4.8)$$

Figure 4.2 can now be expressed in terms of ΔP_m and ΔP_e as follows [11]:

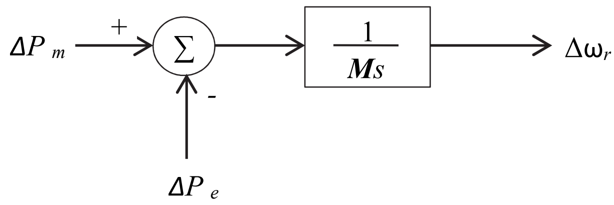

Figure 4.3 Transfer function relating speed and power

Within the range of speed variations that is our concern, the mechanical power of the turbine is fundamentally a function of the valve or the gate position, independent of the frequency.

In reality, the response of a speed governor is slow. The time constants related to the turbines, both hydraulic and steam, are rather long. When the local mode instability was the concern, the speed governors played a negligible part in the system oscillation instability. However, weak interconnections between the systems may give rise to electromechanical oscillations low enough for the speed governor to influence the stability of the inter-area oscillations. In both hydraulic and speed turbines, the elimination of the negative damping effect was achieved by simple phase lead network [34].

When the generators are synchronized, the speed of each generator is identical at the steady state. An increase in the system load power demand causes the system generators to slow down. The governors act to increase the speed, and each prime mover that has a speed governor produces additional torque to accelerate the generator rotor. If the droop of each governor is the same, the power demand is shared between the generators in proportion to their ratings. However, generators with isochronous control will increase their turbine powers in preference to other generators in droop control until their output limit is reached [34].

Many governors have a dead-band. This prevents governor action unless the speed change exceeds the dead-band range, and it is installed to prevent the governor control valves working for continuous small speed changes.

The power system is normally so large that the operation of an individual synchronous generator connected to it has hardly any effect on the whole power system. In the normal operation of the fast grid, when the turbine mechanical power production will be increased, the rotor will try to rotate faster, but the electromotive force of the grid will place an opposing force and the frequency will be stable. A greater electromotive force will cause a greater angle difference between the generator and the grid voltages and this will cause an increase of the generator active power production.

On the fast grid, one synchronous generator cannot affect the system frequency. So it also means that there is no reason to put the turbine governor to control directly the system frequency on the fast grid. Normally in the modern system there is a possibility to select frequency support for the turbine control mode. On this control the turbine governor has a slight speed dropping characteristic with an increasing load. The speed droop (SD) of a turbine governor is defined by [35]:

$$SD = \frac{n_{nl} - n_{fl}}{n_{fl}} \times 100\% \qquad (4.9)$$

where

n_{nl} – no-load speed,

n_{fl} – full-load speed (50 Hz).

When operating connected on the fast grid, the system frequency is stable and if the speed set point (the no-load speed) is changed, the turbine governor will change the turbine power.

If due to network disturbance the system frequency changes, the turbine governor will change in the same way the unit power production and the unit will be supporting the system frequency.

Flexible fast governor systems

In the generation units with PF boilers in the Eesti and the Balti Power Plant a Soviet-made flexible fast governor system is used.

The governor system consists of a centrifugal tachometer, many pin joints, a servomotor drive, etc. All of those connections contain friction, which impedes the movement of the regulation muff. This all is introduced by the governor system dead band. The governor system dead band can be expressed by the following formula [36, 37]:

$$\varepsilon = \frac{2\Delta\omega}{\omega_0} \qquad (4.10)$$

where

$\Delta\omega$ – speed deviation to which the speed controller drive reacts,

ω_0 – rated speed.

The governor system dead band of the Balti and the Estonia Power Plant is 0.3%.

After fresh steam pervade shutoff valve it is directed to four regulation valves. The regulation valve is controlled by the camshaft, which is connected through the gear rack with the servomotor piston.

Modern governor systems

In the generation units with CFB boilers in the Eesti and the Balti Power Plant a modern governor system is used. The automatic turbine controller (TC) has been realized with the Automatic System AS 620 T based on the SIMADYN-D processor. The TC ensures a stable operation of the power plant unit under all operating conditions such as turbine start-up, shutdown and parallel operation at different loads. The turbine controller system consists of two independent channels. Each channel is in a redundant structure. The turbine speed is regulated by an electronic governor, which forms a part of the electronic turbine controller. The earlier mechanical-hydraulic speed governor remains in operation as an additional stage for turbine over speed protection [35].

The turbine controller has the following main functions [38]:

1) Speed control:

The turbine speed controller is used to assist in the start-up of the turbine. Its output signal is the speed set value for the speed controller. The target speed set value is limited by the maximum allowed value, which is based on the operation mode of the turbine. The speed set value is automatically adjusted to zero if the turbine trip is activated.

2) Admission control:

Admission control means an operation mode where the incoming live steam amount can be adjusted manually during certain operating conditions. It may also be automatically turned on due to some failures in the system, e.g. when the frequency is out of normal operating range or if the load and pressure controllers are out of operation.

3) Load control:

Load control means an operation mode where the generator output can be adjusted. When the load control is selected, the live steam pressure controller is simultaneously switched off. This change of the control mode takes also effect automatically if the boiler pressure controller is switched to manual operating mode. The load controller is switched off automatically in case of some disturbances, e.g. when the generator is disconnected from the grid or if the steam pressure in the HPC control stage is less than minimum.

4) Live steam pressure control:

Live steam pressure control means an operation mode where the incoming live steam pressure can be adjusted (± 5 % of nominal pressure). When the live steam pressure control is selected, the load controller is simultaneously switched off. The pressure controller is switched off automatically in case of disturbances, e.g. when the generator is disconnected from the grid or if the steam pressure in the HPC control stage is less than minimum. The pressure controller is also turned off if the TC is switched over to the speed control mode.

5) Minimum live steam pressure control:

If the live steam pressure falls below an allowable value, the minimum live steam pressure controller is switched on automatically. The set value for the controller depends on the boiler design and is normally 85-90 % from the nominal live steam pressure.

6) Hot reheat steam pressure control:

The hot reheat steam pressure controller prevents the decrease of the hot reheat steam pressure before intermediate pressure control valves below 1.6…1.8 MPa. The pressure control will be used only when process steam is produced. In the operation mode with disconnection of the generator from the grid or on the island mode, the speed controller is active. After synchronization and connection of the generator to the grid turbine, the controller automatically switches over to the admission control mode. After high pressure control connection and reach of nominal live steam pressure, the turbine controller can be switched over to the load control mode or the live steam pressure control mode [38].

The output signal of the turbine controller acts to the control valve actuators via electric-hydraulic converters-summators (EHC-S). There are four EHCs in the turbine governing system [38]:

- two of them for high pressure control valves;
- one for intermediate pressure control valves;
- one for low pressure control valves.

In case of turbine controller failure, all the turbine control and stop valves are closed under the force of servomotors springs. In case of emergency opening of the main or generator breakers, the turbine controller limits the dynamic increase of the turbine rotation speed at the value which is lower than over speed protection set point and further maintenance of nominal speed.

The Eesti and the Balti Power Plant units with PF boilers have a governor system dead band of 0.3% and droop of 4 – 5%. The Eesti Power Plant generation unit with CFB boilers has a dead band of ±10mHz and droop of 4%.

Models for governor system modelling

To model the governor systems of the Balti and the Estonia Power Plant, the PSSE model IEEE Type 1 Speed-Governing Model (with abbreviation IEEEG1) can be used [19]. This model can be used both for modelling modern and Soviet-made governor systems. Model input is high pressure shaft speed and outputs are high pressure shaft mechanical power and low pressure shaft mechanical power. IEEEG1 model parameters and recommended settings are shown in Table 4.1.

Table 4.1 IEEEG1 model parameters and recommended settings

Abbreviation	**Name**	**Unit**	**Recommended settings**
K	Governor gain (reciprocal of droop)	p.u.	20
T1	Governor lag time constant	sec.	0
T2	Governor lead time constant	sec.	0
T3	Valve positioner time constant	sec.	0.3
Uo	Maximum valve opening velocity	p.u./sec.	0.1
Uc	Maximum valve closing velocity	p.u./sec	-0.1
Pmax	Maximum valve opening	p.u.	1.1

Pmin	Minimum valve opening	p.u.	0
T4	Inlet piping/steam bowl time constant	sec.	0.2
K1	Fraction of high pressure shaft power after first boiler pass	nr.	0.45
K2	Fraction of low pressure shaft power after first boiler pass	nr.	0
T5	Time constant of second boiler pass	sec.	5.5
K3	Fraction of high pressure shaft power after second boiler pass	nr.	0.55
K4	Fraction of low pressure shaft power after second boiler pass	nr.	0
T6	Time constant of third boiler pass	sec.	0
K5	Fraction of high pressure shaft power after third boiler pass	nr.	0
K6	Fraction of low pressure shaft power after third boiler pass	nr.	0
T7	Time constant of fourth boiler pass	sec.	0
K7	Fraction of high pressure shaft power after fourth boiler pass	nr.	0
K8	Fraction of low pressure shaft power after fourth boiler pass	nr.	0

IEEEG1 model requires large amounts of data, a simpler model for modelling the governor systems is the PSSE model Steam Turbine-Governor (TGOV1). The TGOV1 model input is speed deviation and its output is mechanical power. The TGOV1 model parameters and recommended settings are shown in Table 4.1 [19].

Table 4.2. TGOV1 model parameters and recommended settings.

Abbreviation	Name	Unit	Recommended settings
R	Governor permanent droop	p.u.	0.05
T1	Governor time constant	s	0.5
T2/T3	Turbine high pressure power time constants fraction	s	1.0
T3	Reheater time constant	s	-1.0
Dt	Turbine damping coefficient	p.u.	2.1
Vmax	Maximum valve position	p.u.	7
Vmin	Minimum valve position	p.u.	0

Two models have been introduced for governor system modelling: TGOV1 and IEEG1. The TGOV1 is not commonly used because it is too simple, but it is a good place to start. The IEEEG1 is more common to model a steam turbine governor system.

The next very important task is to verify turbine speed governor system settings. Much research has been published about the identification of governor system settings, [39-42]. Turbine governor system settings of the Eesti and the Balti Power Plant units can be verified by using the Estonian isolation test results from 3-4 April 2009. In the past, 2002 and 2006 isolation test results were used to verify governor system settings of the Eesti Power Plant and the Balti Power Plant units [43].

Replacement of Soviet made speed governor systems should be investigated considering the fact that in the future stricter frequency regulation requirements of the Estonian power system may be set up. For example, if Estonian power system is interconnected to the European power system.

5. Frequency control

Power generation must be equal to power consumption all the time. If this equilibrium between generation and consumption is disturbed, then a power deviation occurs in the system that in turn causes a frequency deviation from its set-point value.

The electric frequency shows the rotation speed of the generators in the synchronized systems. It depends on the balance between power generation and consumption. If the power consumption increases, the rotation speed of the generators decreases, which causes the frequency decrease, and vice versa, if the power consumption decreases, the system frequency increases. To re-establish the equilibrium between generation and consumption and as a result to restore a set-point value of the frequency, an automatic frequency regulation action is necessary by the regulating units. The value of frequency deviation depends on both the total inertia in the system and the speed of the primary control. Under normal conditions, the frequency deviation from its set-point value of 50 Hz must not exceed strict limits in order to provide the full deployment of control facilities in response to a disturbance in the system.

Imbalances and thus frequency deviations cannot be physically avoided for two fundamental reasons [44]:

1) The power demand forecast is subjected to errors and its controllability is limited. Thus, the dispatch of power plants, which is done according to forecasts, causes deviations between generation and consumption.
2) The controllability of power plants is also limited, especially in plants which use fluctuating renewable energy source to generate electricity and the operational equipment is subjected to disturbances.

To maintain a balance between generation and consumption in real-time in case of changes in actual consumption or failure of generation units or transmission lines, a power reserve in the power system must be available. This reserve must be sufficient and fast-running to provide a necessary flexibility in the changes of the power generation level and as a result to provide a reliable electric power supply for end users.

The new Network Code on Load-Frequency Control and Reserves developed by the European Network for Transmission System Operators for Electricity (ENTSO-E) working team has defined new terms for frequency regulation [45]:

1) Frequency containment process (FCP) – activating frequency containment reserves (FCR) in order to achieve constant containment of frequency deviations (fluctuations) from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system. This category typically includes operating reserves with the activation time up to 30 seconds and they are usually activated automatically and locally.
2) Frequency restoration process (FRP) – frequency restoration reserves (FRR) are used to restore frequency to the nominal value and power balance to the scheduled value after sudden system imbalance occurrence. This category

includes operating reserves with an activation time typically up to 15 minutes (depending on the specific requirements of the synchronous area). Operating reserves of this category are typically activated centrally and can be activated automatically or manually.

3) Reserves replacement process (RRP) – replacement reserves (RR) are used to restore the required level of operating reserves to be prepared for a further system imbalance. This category includes operating reserves with activation time from 15 minutes up to hours.

Hence, the term primary regulation reserve is now replaced by frequency containment reserves and the secondary and tertiary reserves are now replaced by frequency restoration reserves.

Figure 5.1 shows frequency regulation phases [44].

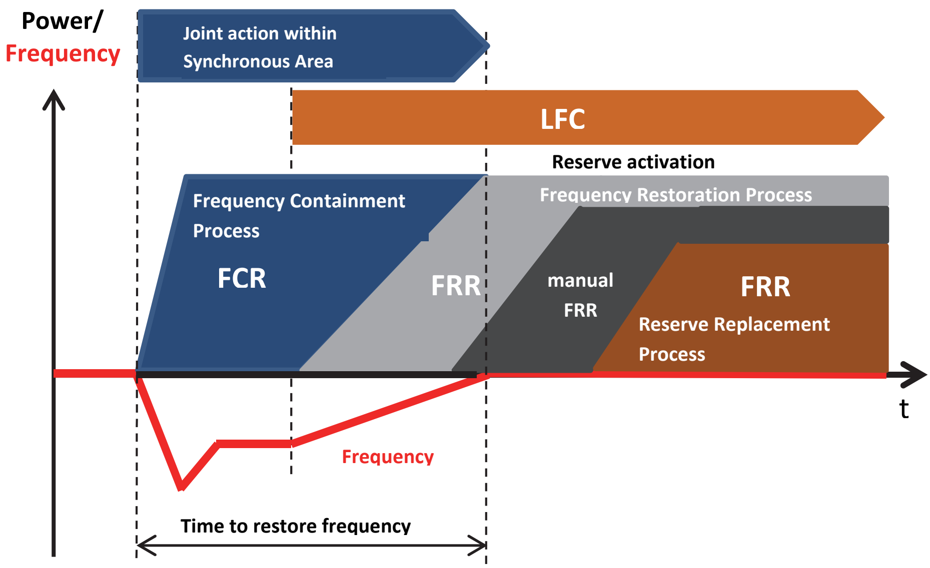

Figure 5.1. Frequency regulation phases.

PAPER IV presents an overview of power and frequency control principles used in IPS/UPS and ENTSO-E synchronous areas. This paper compares the norms and standards of IPS/UPS and ENTSO-E power and frequency control and defines the main differences and similarities between them. Also, several articles have been written about frequency regulation in IPS/UPS synchronous area [46, 47].

In addition, new ENTSO-E frequency regulation phases are briefly introduced.

5.1. Frequency containment process

Frequency containment process means a restoration of the system frequency at an acceptable level after a disturbance by activation of Frequency Containment Reserve (FCR) that, in its turn, compensates imbalance between generation and load. This process maintains frequency within defined limits, but does not restore it to the set point. The activation of FCR in the whole synchronous area provides the balance between generation and demand for each TSO area, however it does not restore the power exchanges between the areas of different TSOs at their set-point value.

In case of disturbances in the system that cause a deviation of the frequency from its set point, the FCR controller of reserve providing units, which is involved in the FCR control, will immediately react to this deviation and, as a result, the system frequency will be restored at an acceptable stationary value. If it is not succeeded to maintain the system frequency within permissible limits, additional actions are required and carried out on order to maintain interconnected operation. Additional actions can, for example, be automatic load shedding. Figure 5.2 shows FCR interaction with other operational reserves [48].

FCR controller of the involved reserve providing units reacts to the frequency deviation, which exceeds its certain insensitivity range, within a few seconds. As a result, reserve providing units will be activated and their power output will be adapted to the new level of generation that provides the restoration of the balance between generation and demand in the system. After that the system frequency stabilizes and remains at an acceptable stationary value that, however, differs from the initial set-point value.

According to the principle of joint action in the synchronous area, all reserve providing units of the synchronous area participate in the restoration of the balance in the area disturbance occurred. Therefore after re-establishment of the balance power exchanges in the interconnected system differ from their scheduled values.

The principle of FCR action is based on a linear correlation that provides direct reaction of FCR on the frequency deviation in the system. After re-establishment of the balance between generation and load and return of the system frequency and / or cross-border exchanges to their set-point value the action of frequency restoration reserves (FRR) will be deployed. Generally, FCR requirements can only influence the quality parameters of the system frequency that are connected to the system stability criteria.

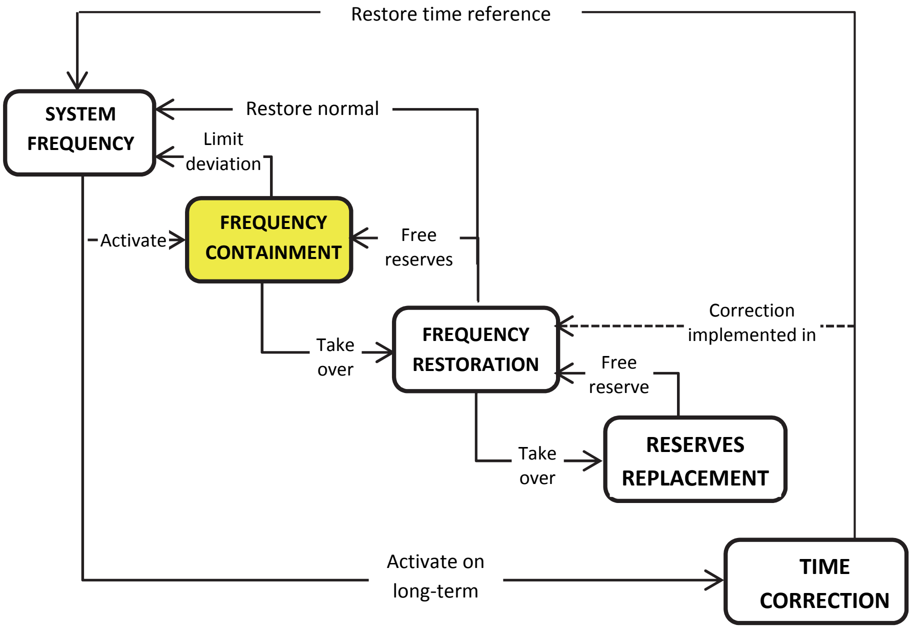

Figure 5.2 FCR and interaction between operational reserves

The dynamic behavior of the system frequency is governed mainly by the following [44]:

- 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 (system inertia);
- the number of reserve providing units providing FCR, and the amount of FCR available and its distribution;
- all reserve providing units' droop subject to FCR in the synchronous area;
- the dynamic characteristics of the machines (including controllers);
- the dynamic characteristics of loads, particularly the self-regulating effect of loads.

The action of FCR must last until the FRR is activated in the area where the disturbance occurred. The FRR re-establishes the system frequency to its set-point value and provides the restoration of FCR.

Imbalances in the system that caused not by the trips of load or generation, but by other events, also may lead to the system frequency deviations that, in its turn, causes the deployment of some FCR providing units. When some FCR are already activated to eliminate the frequency deviations caused by other events than trips, these FCR providing units are not ready to counteract the effects of a generating unit/load trip. In case of large frequency deviations caused by other events than trips, it takes more time to counteract them. If a large generation/load imbalance incident occurs at the time some FCR are already in use because of the deviations caused by other events, it may occur that available rest FCR is not sufficient to counteract this generation/load imbalance. This may lead to a situation when frequency deviations exceed permissible limits and, consequently, to load-shedding. Therefore the number and length of frequency deviations caused by other reasons than trips must be limited.

5.2. Frequency restoration process

Frequency restoration process means a restoration of the system frequency at its set-point value in the time frame defined within the synchronous area by activating the frequency restoration reserve (FRR) and releasing the frequency containment reserve (FCR). If the frequency restoration control is decentralized, the aim of FRR is also to re-establish balance between generation and load for each TSO area and, as a result, to restore power flows between TSO's areas to their scheduled values.

The main object of FCR is to stabilize the system frequency after disturbance caused by instant imbalance between generation and load. After the system frequency has been stabilized and restored at its quasi-steady state value, FRR is deployed and re-establishes the frequency to its set-point value. Thus, FRR releases FCR to restore and be able to counteract the next disturbances in the system. When FRR is exhausted, Replacement Reserve (RR) is deployed to release FRR to restore and cope with the next failure.

There are two opportunities for organization of FRR: central frequency control per synchronous system or, in a large synchronous system, decentralized load-frequency control in control blocks. The organization of FRR is performed per synchronous area. Figure 5.3 shows FRR interaction with other operational reserves [48].

FRR should be able to fully restore the system frequency to its normal range after failures, larger imbalances and during normal volatility. The "normal volatility" is usually caused by the deviations of generation or demand from their scheduled values. TSO has to cover this imbalance during the period the balance responsible parties cannot re-establish their balance by themselves. The balance responsible parties are expected to compensate the remaining imbalance in their balance area by selling/buying the necessary power volume on intraday market.

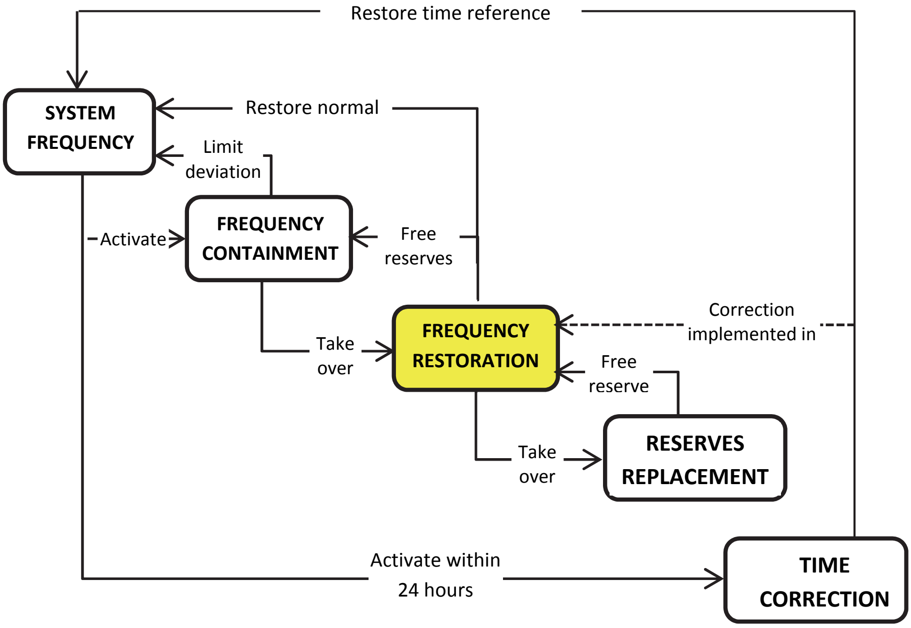

Figure 5.3 FRR and interaction between operational reserves

To change the generation or consumption level during FRR manual activation, the following acts are used:

- connection and tripping of power (unit commitment);
- redistributing the output from generators participating in FRR;
- altering the power interchange program;
- load control;
- optimal load dispatch between power units and boliers.

Since the TSO has frequency control commitments, it can decide which part of the capacity of FRR/RR is contracted as firm capacity and which part acts on the market base and, consequently, is subject to changes.

5.3. Replacement reserve process

The subject of replacement reserve (RR) is to release FCR / FRR in case this reserve has been activated up to a certain extent to restore it for the next failures or imbalances. If the TSO activates RR to compensate the imbalance of the market participant, it may occur when market participants have no possibilities or the necessary information to cover this imbalance, the volume of needed reserve and the duration of its activation are highly dependent on the market design of each country. RR may be activated manually and centrally by the TSO at the control center if it is observed or expected that FRR be restored or in case of the lack of imbalance compensation on behalf of balance responsible parties. RR may be also activated to anticipate expected imbalances.

5.4. Summary of the Estonian system isolation test

It is difficult to investigate the frequency regulation quality of a single power system, because during frequency deviation all power stations in a synchronous area will react to restore system frequency to the set point value. In case of the Estonian power system, such frequency regulation is essentially performed by the Russian power system. The peak load of the Estonian power system is approximately 1540 MWh, whereas the Russian power system's peak load is approximately 147 000 MWh – thus, the Russian system is about 100 times larger than the Estonian one [49]. Therefore, the Russian power system has a vast influence on frequency regulation in Estonia.

Currently the Estonian TSO is responsible to keep one hour's active power imbalance in the range of ± 30 MWh, and nowadays it is only a regulated responsibility for the Estonian power system to participate in the frequency regulation. In the foreseeable future, it is quite probable that the frequency regulation requirements for the Estonian power system will be set at a more severe level than today. This is likely to occur, for instance, in case the frequency regulation principles change between Estonian and Russian TSOs, or if the Estonian power system interconnects with the European power systems. The most efficient way to examine the quality of frequency regulation of the Estonian power system would be to carry out an isolation test. During such a test the Estonian power system would need to be separated from the rest of the BRELL system, and based on the test results, the frequency regulation quality can be evaluated.

A number of isolation tests have been made in the past, including the following more important tests:

- 20 May 1995: Estonian power system and part of Latvian power system were separated from BRELL power systems,
- 22 May 1997: part of the east of the Eesti and part of the Balti Power Plant were separated from the Estonian power system,
- 5 April 2002: Estonian, Latvian, Lithuanian, Kaliningrad, and part of the Belorussian power systems were separated from the rest of the BRELL system,
- 10 November 2006: Estonian power system was separated from the BRELL system,
- 3-4 April 2009: Estonian power system was separated from the BRELL system.

5 April 2002 isolation test purpose was to investigate frequency regulation quality in Baltic countries [50]. Main aim of 10 November 2006 isolation test was to check frequency regulation capability of modernized power units in Balti Power Plant and in Eesti Power Plant [51].

The results of the isolation test performed on 3-4 April 2009 were selected for further analysis, because it is the latest isolation test so far and it will therefore provide arguably the most accurate and representative background data for describing the capability and quality of frequency regulation of the Estonian power system. In PAPER IV and in this thesis data collected by Elering during all stages of the isolation system are used. Data were measured by the SCADA system and measuring equipment LEM and REMI.

PAPER III presents the ENTSO-E methodology for the calculation of characteristic numbers of the primary control and introduces the isolation test of 3-4 April 2009. In this section, the isolation test of 3-4 April 2009 is closely discussed. All 3-4 April 2009 isolation test calculations were done according to the ENTSO-E methodology for the calculation of characteristic numbers of primary control [52].

The isolation test in the Estonian power system was performed from 3 to 4 April 2009. The author of this thesis participated in the isolation test as Head of Operational Planning in the Estonian Dispatch Center and was member of the team who analyzed the results of this isolation test. The Estonian power system was separated from the BRELL system, which unites Belorussian, Russian, Estonian, Latvian and Lithuanian power systems. However, not all of the BRELL transit was interrupted in the Estonian power system. Power transit flows from Russia to Latvia went through Pihkva-Velikoretskaja-Rezekne and Pihkva-Tartu–Valmiera–Salaspils substations at the level 330 kV, as shown in Figure 5.4. The isolation test was started at 23.30 (Estonian time here and onward) on 3 April 2009.

The main object of the isolation test was to check the frequency regulation quality in the Estonian power system during isolated operation. To fulfil this aim, the following tasks were planned to be investigated:

1. to investigate the capability and quality of frequency regulation in the isolated Estonian power system during the fast and slow changing active power balance in the Estonian power system;
2. to conduct the test of automatic frequency control function (AFC) of high voltage direct current (HVDC) link in the isolated Estonian power system;
3. to specify the frequency characteristics of the AFC of HVDC and for the Eesti and the Balti Power Plant units;
4. to specify the load frequency characteristics P=f(U) of the South and Eastern Estonia;
5. to obtain data for the verification of the existing model of HVDC link;
6. to verify the black start function (BSF) of HVDC link.

In this thesis task 1-5 results are discussed. The isolation system of the Estonian power system is shown in Figure 5.4.

Fi

Figure 5.4 Isolation scheme of the Estonian power system

The isolation test was divided into five stages. Table 5.1 shows the stages of the isolation test and the actions taken during each stage.

Table 5.1 Isolation test stages and actions of these stages in the Estonian system

Stage number	Actions
1	- isolation of the Estonian power system from the BRELL system with planned surplus about 80 MW; - the Estonian power system regulates frequency by itself without the AFC of HVDC link; - the Estonian power system operation with frequency regulation by the AFC of HVDC link
2	- shutting down of one boiler of unit 3 in the Eesti Power Plant with output decreasing about 70 MW;
3	- output increasing to the level 90 MW in unit 6 of the Eesti Power Plant, which was in operation with one boiler, afterwards switching off unit 6;
4	- AFC of HVDC link is switched off and the Estonian power system regulates frequency by itself; - switching in unit 12 in the Balti Power Plant with its minimum output; - determination of characteristics dP/dU in the South and Eastern Estonia;
5	- restoring of synchronous operation of the Estonian power system with the BRELL system.

The first stage of the isolation test began at 00:09:35, when the last 330 kV line (Eesti power plant – Kingisepskaja substation), which connected the Eesit power station with the BRELL system, was swiched off and the Estonian power system started regulating frequency only by the power plant units and the AFC of HVDC link was switched off. The actual surplus of the Estonian power system was 72.9 MW, frequency before separation was 50.017 Hz and right after the separation the frequency was 50.171 Hz. At 00:13:50 the AFC of HVDC link was switched on and started regulating freguency of the Estonian power system. The second stage of the test began at 00:17:26. The output of unit 3 in the Estonian power system was decreased by shutting down one boiler, unit 3 output was decreased about 70 MW, the AFC of HVDC link was in operation. The third stage began at 00:32:13, output increasing to the 100 MW in unit 6 of the Eesti Power Plant and when unit 6 in the Eesti Power Plant was switched off, the AFC of HVDC link was in operation. At 00:38:31 the fourth stage of the isolation test started. The AFC of HVDC link was switched off. Voltage in the Tartu and Narva areas started fluctuating. The fifth stage began at 01:13. At that stage synchronous operation of the Estonian power system with the BRELL system was restored.

The Estonian power system was isolated from the synchronous operation with the BRELL system from 4 April 2009 at 00:09:35 and the isolation test was finished on 4 April 2009 at 1:13:39 by synchronizing this system with the BRELL system. The Estonian power system operated separately from the BRELL system all together 1 hour 40 minutes.

Frequency change during the isolated operation in the Estonian power system during the different stages of the test is shown in Figure 5.5.

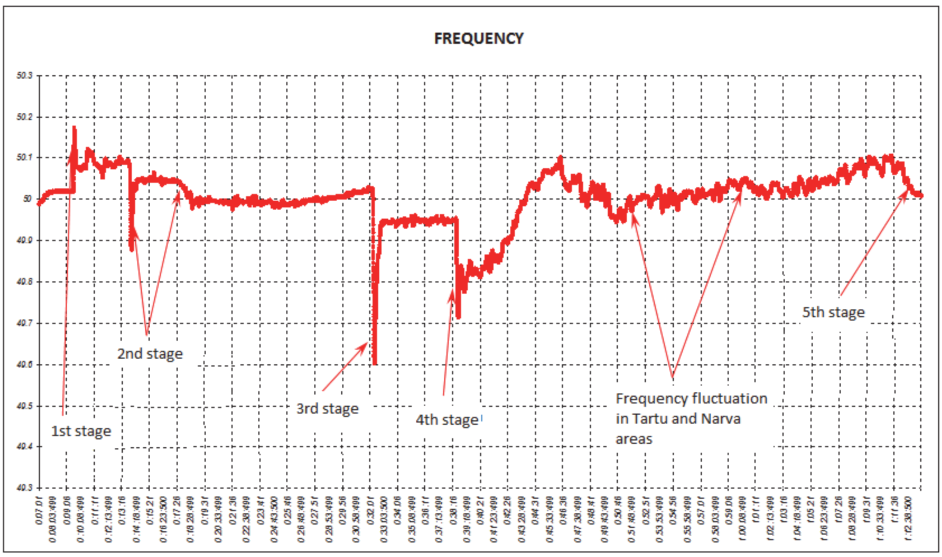

Figure 5.5. Frequency change in the Estonian power system during the isolated operation

Verification of the Estonian grid code correspondence of the Eesti Power Plant and the Balti Power Plant units was not the object of that test. As a result, appropriate conditions to verify the Estonian grid code correspondence of the parameters of power plants units were not created. Conditions that made the test results inaccurate:

1. To perform the test of the type, the power system should be in a steady condition, for example, during off peak or peak load hours.
2. During all stages, every unit under investigation must have at least 5% of rotation reserve.
3. Dead band of all unit controllers must be determined beforehand and communicated to all involved personnel.

According to the results of the isolation test of the Estonian power system, the following conclusions can be made:

1. The capability and quality of frequency regulation in the isolated Estonian power system during the fast and slow changing in supply were investigated. The Estonian system is able to operate separately from the BRELL system. According to the test results, it can be concluded that the frequency regulating quality of the Estonian power system is satisfactory. The frequency deviation was calculated on the basis of average values of measurements that were taken during 20-second intervals after a failure occurred. The results of that calculation showed that frequency deviation was in the permitted range and did not exceed 50±0.2 Hz during all stages of the isolation test, which was calculated by using 20 seconds interval averages [53].
2. The test of the automatic frequency control (AFC function) of HVDC link in the isolated Estonian power system was conducted. After the AFC of HVDC link was switched on, the power flow of 73 MW occurred in the direction to Finland. This flow lasted only for 3 seconds, however it caused power shortage in the isolated system. The power flow caused a frequency deviation that in turn caused the reaction of the primary regulation of the Eesti Power Plant and the Balti Power Plant units, during 30 seconds the Eesti Power Plant and the Balti Power Plant units regulated up by +43 MW. This behavior of the HVDC link was unexpected and impermissible, therefore additional investigation is needed. Active power fluctuations of the HVDC link and the Estonian power system frequency during the HVDC switch on are shown in Figure 5.6.

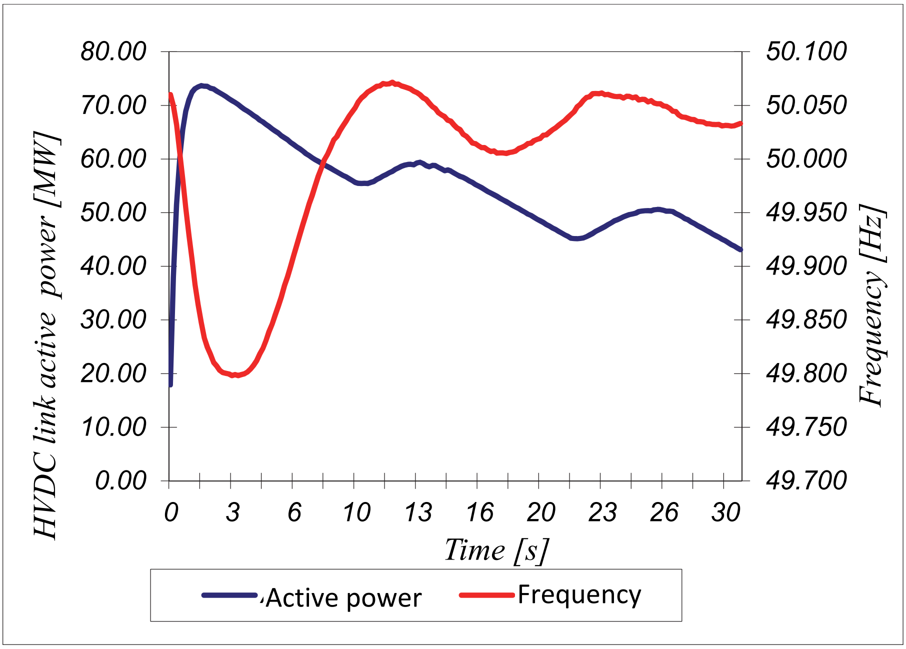

Figure 5.6. Active power fluctuations of HVDC and Estonian power system frequency during HVDC link switch on

After the initial false response, in all other isolation test stages HVDC link performed as intended. Furthermore, in 2007 HVDC link adequately participated in frequency regulation in Finnish power system for almost two weeks [54].

3. During the 2nd and 3rd stage, the AFC of HVDC performed as intended. During the 2nd stage the AFC of HVDC work regulated the frequency all by itself and the generator units did not respond. During the 3rd stage when power shortage was quite large and rapid, generation units also participated in the frequency regulation alone with the AFC of HVDC.
4. The frequency characteristics of the AFC of HVDC link were specified. The skew factor of the frequency characteristic of the HVDC link was calculated for the 2nd and 3rd stages of the test during sharp changes in power generation in the system. The value of the skew factor that was calculated on the 2nd stage of the test was smaller than the value that was assigned by the manufacturer. The value of the skew factor that was calculated on the 3rd stage of the test was the same as assigned by the manufacturer. To calculate the skew factor of the frequency characteristic for the HVDC link, the same method as in the calculation of the system frequency characteristic was used.
5. The frequency characteristics of the Eesti Power Plant and the Balti Power Plant units, which were in operation during the test, were

calculated for all stages of the test. The droops of the generators of Eesti Power Plant and the Balti Power Plant that were calculated for each stage of the test were in the permitted range. The calculation of generator droops in the Eesti Power Plant and the Balti Power Plant is shown in Table 5.2.

Table 5.2. Calculated generator droops in the Eesti Power Plant and the Balti Power Plant units during 4 stages of the isolation test

Generator number	**Frequency deviation**	**Power change**	**Calculated droop**
Unit	%	%	%
TG1	0.30	-12.4	2
TG3	0.30	-6.7	4.6
TG5	0.30	0	-
TG6	0.30	-	-
TG7	0.30	-3.0	10
TG8	0.30	-4.1	7
TG11	0.26	-1.4	-

The total power change in the system corresponded to failure and the requirement of 5 % was met, however it was obtained fast, during the first 10 seconds.

6. System contribution to the frequency regulation includes two parts: load change and governor system work. The frequency characteristics P=f(U) of the South and Eastern Estonia were specified. If we compare the characteristics of the isolation test 2009 with those obtained during the isolation test 2006, it can be concluded that the character of the customer power demand has changed. Also, test results showed the decrease of reactive power effect in the voltage regulation, which is the result of decreasing industrial power demand in the South and Eastern Estonia and increasing number of reactive power compensation devices in the distribution networks.

Table 5.3. Effect of South Estonia voltage regulation in the isolation test 2009 and 2006

Voltage regulation effect	Isolation test in 2009	Isolation test in 2006
Active power voltage regulation effect ($k_{P,U}$)	0.8	1.0
Active power voltage regulation effect ($k_{Q,U}$)	3.3	12

$k_{P,U}$ and $k_{Q,U}$ are calculated as follows:

$$k_{P,U} = \frac{\Delta Pk}{\Delta U} \tag{5.1}$$

$$k_{P,U} = \frac{\Delta Qk}{\Delta U} \tag{5.2}$$

where

ΔPk – change in active power,

ΔQk – change in reactive power,

ΔU – change in voltage.

Frequency regulation characteristics calcutaled during the isolation operation are different from those calculated when the Estonian power system worked synchronously with the BRELL system. However, the deviations of these characteristics from the standard criteria did not exceed 50±0.2 Hz. This deviation was in the permitted range of frequency fluctuation for the isolated system. Frequency regulation by the HVDC link was better than the frequency regulation of power station units. Generally, the isolation test was conducted in accordance with a confirmed plan without unforeseen circumstances.

It is impossible to conclude from the results of that analysis if the Estonian power system is able to regulate frequency by itself during a longer period of time. Neither is it possible to establish the economic effect gained by Estonian consumers and market participants if the Estonian power system regulates frequency by itself. It is also required to address the issue of changing Soviet-made governor systems to modern governor systems within the studies of long-term frequency regulation capability. Further, neither did the analysis provide an answer if the Eesti Power Plant and the Balti Power Plant units are able to fulfill the requirements of the Estonian grid code. It can be concluded from the analysis that the Estonian power system can regulate frequency by itself, at least in a short period of time and fulfill all the frequency regulation quality requirements. Frequency deviation was in the permitted range and did not exceed 50±0.2 Hz during all the stages of that isolation test.

6. Optimal load dispatch between power units and boilers

As was mentioned in section 5.2, the frequency restoration process, optimal load dispatch between power units and boilers is one of the actions, which can be used during the FRR manual activation. Load dispatch optimization between the power units and the boilers should be based on the economic analysis. The aim of this optimization is to minimize expenditures of power generation.

Ordinarily, we assume that initial information for optimization is complete, which means that the information is presented in the deterministic form and values of the data are absolutely exact. In practice, the information for the optimization of thermal power plant operation is inexact and thus incomplete [55, 56]. The information is incomplete if it is inexact or presented in the non-deterministic form.

First of all deterministic information about the input-output characteristics of power units is inexact. This is caused by random errors at the determination of characteristics and changing the characteristics during the operation process and after maintenance and repairs.

The second main reason why the information for power plant optimization is incomplete is the random deviations of controllable and uncontrollable variables. Oil shale and other low heating value fuels have many uncontrollable variables which give rise to uncontrollable boiler parameters.

Oil shale as a fuel is characterized by an extremely high volatile matter content (85 to 90 percent in the organic part) and by formation of ash rich char (the density of combustible matter in char particles is 0.08 to 0.12 g/cm3) [5]. The majority of heat transfer surfaces in an oil shale boiler operate in the conditions where unlimited growth of the ash deposit takes place. Ash deposit in boiler surfaces reduces heat transfer and as a result reduces boiler efficiency, rises flue gas temperature and raises heat loss with flue gas leaving the boiler. To inhibit the growth rate of the ash deposit and to stabilize heat transfer, boiler heat exchange surfaces are equipped with cleaning systems. Currently, pulverized fire boilers are periodically cleaned of ash deposit, typical time period is once every 2 weeks. Also, during boiler maintenance work, typically once a year, boiler heat transfer surfaces are thoroughly cleaned. Thus, the efficiency of oil shale boilers is changing over the time due to ash deposit condition on the heat transfer surfaces.

At full load of the boiler the flue gas temperature before the furnace platens is 1200 to 1250 ºC; after intermediate platens of the reversing chambers, it is 800 to 900 ºC and in the down flow gas pass after the long platen super heaters, it is 680 to 750 ºC. Figure 6.1 shows the temperature change of one boiler of the Eesti Power Plant in the reversing chamber between two boiler cleanings.

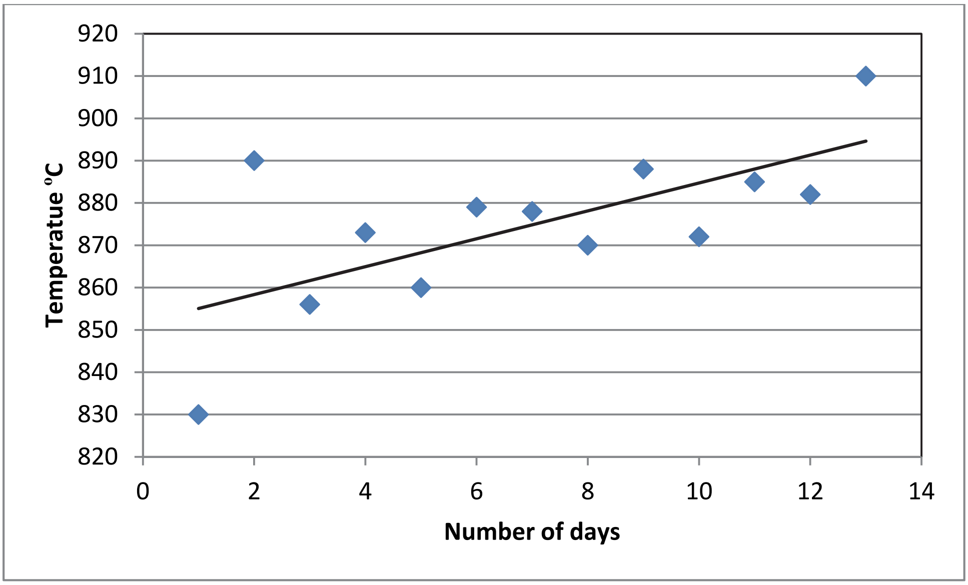

Figure 6.1. Temperature change in the reversing chamber between two boiler cleanings

Figure 6.2 shows the temperature change in one boiler of the Eesti Power Plant in the reversing chamber after yearly maintenance.

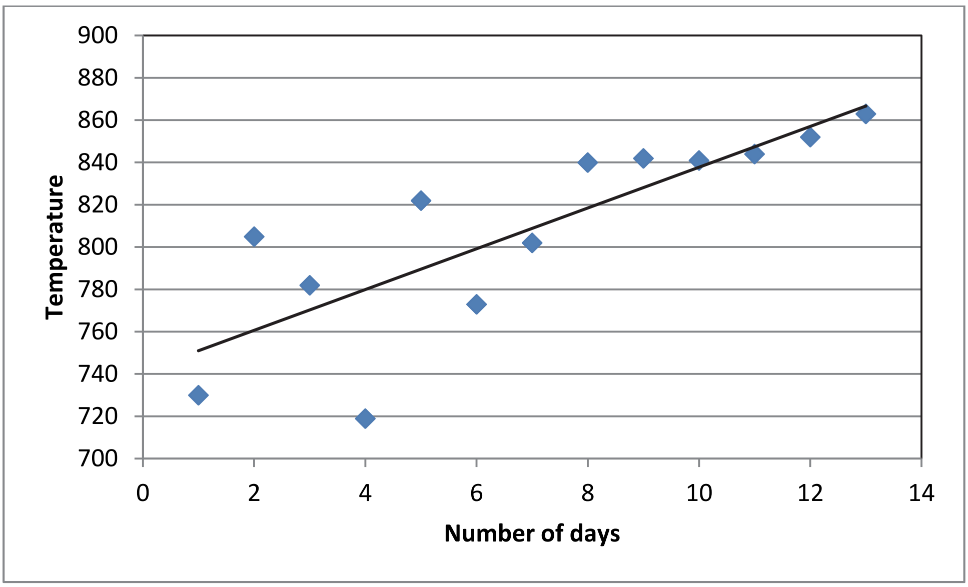

Figure 6.2. Temperature change in the reversing chamber after yearly maintenance

As Figures 6.1 and 6.2 show, temperature rises quite rapidly, because of the increased ash deposit of the boiler surface. These and a number of other stochastic factors decrease the economic effect of the optimization of the power plant operation and cause the fuel over costs.

PAPER II, Table 1 presents the statistical analysis of oil shale parameters in the Eesti Power Plant and in same PAPER, Table 2 presents the statistical analysis of deviation in the turbine and boiler parameters. Data in both tables show that oil shale, boiler and turbine parameters are changing quite significantly.

Information can be divided into four groups [57]:

1. Deterministic information
2. Probabilistic information
3. Uncertain information
   3.1. Uncertain deterministic information
   3.2. Uncertain probabilistic information
4. Fuzzy information:
   4.1. Fuzzy deterministic information
   4.2. Fuzzy probabilistic information

This study analyzes optimal load distribution between the generation units, taking into account that initial information is in probabilistic and in uncertainty form.

In order to minimize the over costs of incomplete information, it is necessary to elaborate special models and methods of optimization.

6.1. Optimization of load distribution under uncertain conditions

Optimal load distribution between power plant units and boilers is an important task from the economic point of view. Let us start from the deterministic problem of load distribution optimization between the power units.

Deterministic problem of optimization is the following [58]:

Minimize:

$$B = \sum_{e=1}^{v} B_{Ue}(P_{Ue}) \quad (6.1)$$

Subject to the constraints:

$$P + \sum_{e=1}^{v} P_{Ue}^{Aux}(P_{Ue}) - \sum_{e=1}^{v} P_{Ue} = 0 \quad (6.2)$$

$$P_{Ue}^{Min} \leq P_{Ue} \leq P_{Ue}^{Max}, e = 1, \ldots, v \quad (6.3)$$

where:

B – total fuel costs of the power plant,

$B_{Ue}(P_{Ue})$ – fuel cost characteristic of power unit e,

P – net load of the power plant,

$P_{Ue}^{Aux}(P_{Ue})$ – characteristic of auxiliary power for unit e,

v – number of operating power units.

If the deterministic information about $B_{Ue}(P_{Ue})$, $P_{Ue}^{Aux}(P_{Ue})$, P, P_{Ue}^{Min} and P_{Ue}^{Max} is sufficiently exact and the planned values of unit loads are realized sufficiently exactly, the optimal load distribution between the operating units may be calculated on the basis of the deterministic problems. If the deterministic and also the probabilistic information for load distribution optimization are completely inexact, the initial information has to be presented in the uncertain form.

Uncertain deterministic information

The uncertain deterministic information determines only the intervals of deterministic information, but the actual value of the object is uncertain. This form of information enables the description of the uncertainties in the given interval objects and taking into account uncertain errors of deterministic information. The uncertain deterministic information may be looked at as a deficiency of probabilistic information, which lacks the probabilistic characteristics. Here only the set of eventual values is given.

The uncertain deterministic information is more general than the deterministic information. All types of the deterministic information may be presented in the uncertain deterministic form. It is not possible to do the contrary.

An example about the uncertain deterministic information:

1. Uncertain deterministic information about an uncertain variable: $90 \leq \tilde{X} \leq 130$.
2. Uncertain deterministic information about a function $\tilde{G}(X)$: $G^-(X) \leq \tilde{G}(X) \leq G^+(X)$, where $G^-(X)$ and $G^+(X)$ are given border functions.

6.2. Criteria for optimization load dispatch under uncertain information

Next we will examine the problem of economical dispatch on the basis of uncertain information about input-output curves of units. Uncertainty of information means that only intervals of characteristics are given. In the given intervals the characteristics are uncertainties. There are several possibilities for optimization of load dispatch of units under uncertainty [59]:

1. Laplace criterion
2. Minimax cost criterion (Wald crieterion)
3. Minimin cost criterion
4. Hurwicz criterion (pessimism – optimism criterion)
5. Min-max risk criterion (Sawage criterion)

The best criterion for the economical dispatch problem under uncertainty is the min-max regret criterion. This criterion is also named a criterion of min-max risk or losses caused by uncertainty of information. The min-max risk criterion guarantees that maximum losses stemming from the uncertainty of information will be as small as possible.

Minimax risk criterion (Sawage' min-max regret criterion)

In PAPER II the min-max risk criterion is used to calculate the input-output characteristics of power units under incomplete information. In 1954 L. Sawage recommended to use the min-max regret to the min-max risk criterion. In the case of that criterion the maximum losses caused by uncertainty of information are minimized. The criterion is called min-max losses, min-max risk or Sawage's criterion.

The minimax risk criterion occasionally enables a decrease of the maximum risk about two times.

The min-max risk criterion is the main criterion of optimization under uncertainty. This criterion is suitable for the optimization of load distribution and unit commitment under uncertainty.

The optimization problems under incomplete information may be solved by the method of planning characteristics.

6.3. The initial mathematical model of a power unit

The input-output characteristic of a condensing unit can be presented as a composite function:

$$C = cB(Q_T\,(P)) = C(P) \tag{6.4}$$

where

c – price of fuel,

C– fuel cost of the unit,

P– power output of the unit,

$B(QB)$ – input-output characteristic of a boiler, assuming that QB = QT,

Q_T – heat input of the turbine,

$Q_T(P)$ – input-output characteristic of the condensing turbine,

$C(P)$ – input-output characteristic of the condensing unit.

Cost functions of condensing power units are usually continuous, piecewise smooth and strictly convex.

The most important characteristic for solving the problem of optimum dispatch in a power plant is the characteristic of incremental cost rate:

$$\beta = \frac{dC(P)}{dP} \tag{6.5}$$

If a power unit consists of a turbine and two boilers (double unit), the optimization of a power unit control means optimal dispatching of the thermal power of the two boilers at the turbine input. In Eesti Power Plant and Balti Power Plant all power units are double units.

Input-output characteristics of boilers and power units depend on many parameters, which are characterized by random deviations from their nominal or planned values.

To solve an optimal load dispatch in a power plant under incomplete information, the method of planned characteristics may be used [60, 61].

Computation of an optimal load dispatch in a power plant under the probabilistic or uncertain information consists of two stages:

1. Computation of planned characteristics of power units and construction of deterministic equivalents.
2. Solution of deterministic equivalents.

6.4. Calculation of planned characteristics under probabilistic information

Let us assume that all initial functions (characteristics of power units, of boilers and of auxiliary power) and uncontrollable parameters are random functions and variables, the initial information on which is available in probabilistic form. Input-output characteristics of boilers depend on flue gas temperature after the boiler, fuel parameters, etc. Turbine characteristics depend on vacuum in the condenser, steam pressure and temperature at the inlet of the turbine, etc. All these parameters are random. On the basis of probabilistic information, it is possible to calculate new characteristics of a boiler and a turbine by the following formulas [62]:

Boiler:

$$C_B(Q_B) = C_B(Q_B, m_{X1}, \dots, m_{Xn}) + \frac{1}{2}\sum \frac{\partial^2 C_{Bj}(X)}{\partial X_j^2}\sigma_{Xj} + \frac{1}{2}\sum_{k=1}^{n}\sum_{j=1}^{n}\frac{\partial^2 C_B(X)}{\partial X_k \partial X_j} \times k_{Xk}k_{Xj} \quad (6.6)$$

where

P – power output of the unit,
C_B – fuel cost of the boiler,
Q_B – heat input of the boiler,
m – mathematical expectations of parameter,
σ – root -mean-square of parameter,
k – correlation factor,
x – parameter.

Turbine:

$$Q_T(P) = Q_T(P, m_{X1}, \dots, m_{Xn}) + \frac{1}{2}\sum \frac{\partial^2 Q_T(X)}{\partial X_j^2}\sigma_{Xj} \quad (6.7)$$

where

P – power output of the unit,
C_T – fuel cost of the turbine,
Q_T – heat input of the turbine,
m – mathematical expectations of parameter,
σ – root -mean-square of parameter.

Figure 6.3 shows the initial and planned incremental cost rate characteristics (in relative units) of the power unit.

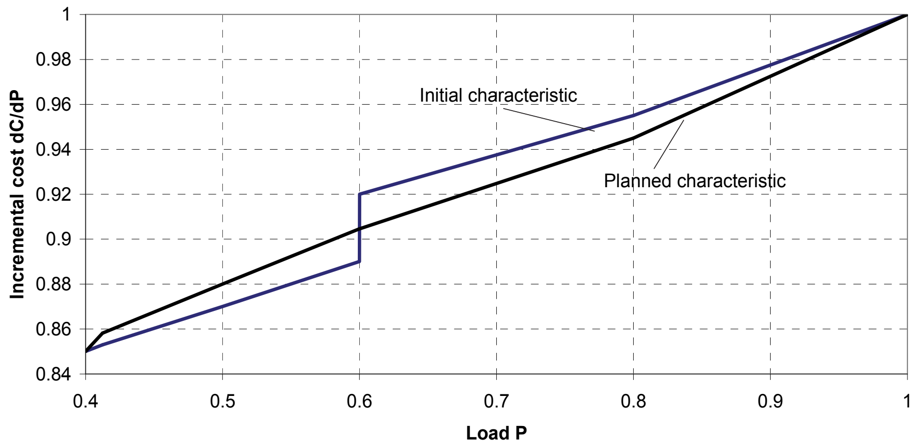

Figure. 6.3. Initial and planned incremental cost rate characteristics (in relative units) of the power unit.

PAPER II, Figure 1 presents the initial and planned characteristics of the boiler and in same PAPER, Figure 2 presents the initial and planned characteristics of the turbine.

6.5. Calculation of planned characteristics under uncertain-deterministic information

The first step in the calculation of the planned characteristics is the calculation of the characteristics of the initial lower and upper incremental cost rate of the power units.

The lower characteristic must be determined as a characteristic in case all the operation parameters of the power unit are on the best level, and the upper characteristic – in case all the operation parameters are on the worst level, for example, the worst fuel, the worst vacuum in the condenser, the worst state of furnaces of boilers and so on.

The lower characteristic of the power unit may be calculated by the formula:

$$\beta^{-}(P) = \beta(P) - \sum k_i \times \Delta x_i^{-} \qquad (6.8)$$

where

β(P) – initial characteristic of the incremental cost rate of the power unit,

k_i – correction coefficient of operation parameter deviation,

ΔX_i^{-} – deviation of operation parameter towards the direction which reduces the incremental cost rate of the power unit.

The upper characteristic of the power unit may be calculated by:

$$\beta^{+}(P) = \beta(P) - \sum k_i \times \Delta x_i^{+} \qquad (6.9)$$

where

ΔX_i^{+} – deviation of the operation parameter towards the direction which increases the incremental cost rate of the power unit.

The calculations show that the zone of uncertainty of incremental cost rate characteristics is about 10% in boilers, about 7% in turbines, and up to 20% in power units.

Uncertainty zone of the incremental fuel cost characteristic of the double power unit is shown in Figure 6.4 [58]. The zones of uncertainty are given by two deterministic characteristics.

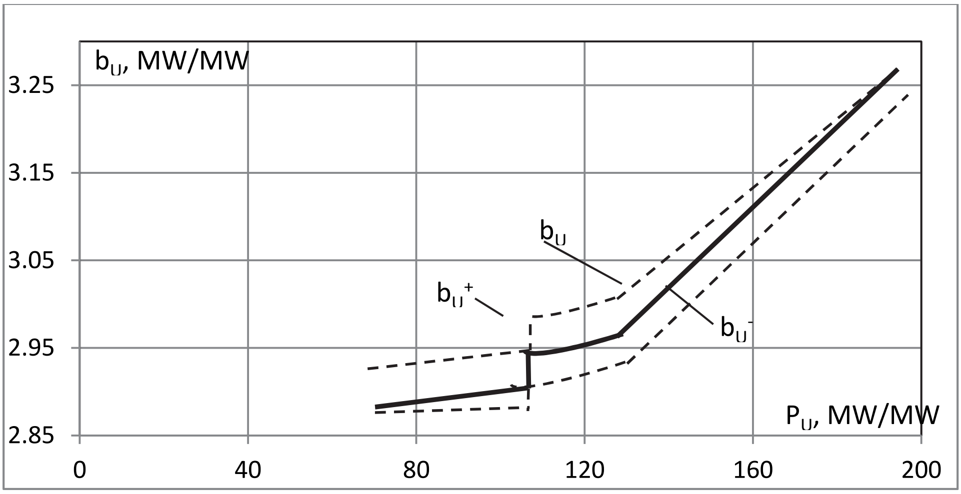

Figure 6.4 Uncertainty zone of the incremental fuel cost characteristic of the double power unit

The min-max planned characteristics can be calculated by various approximate methods [61, 63].

The simplest method for the calculation of min-max planned characteristics is as follows:

1. Choose different values of the incremental cost rate of a power plant.
2. Calculate the min-max load distribution by the chosen values of incremental cost rates.

The min-max incremental fuel cost characteristic of a boiler is shown in Figure 6.5. The point of the planned incremental cost characteristic is found from the equation in areas S1 = areas S2.

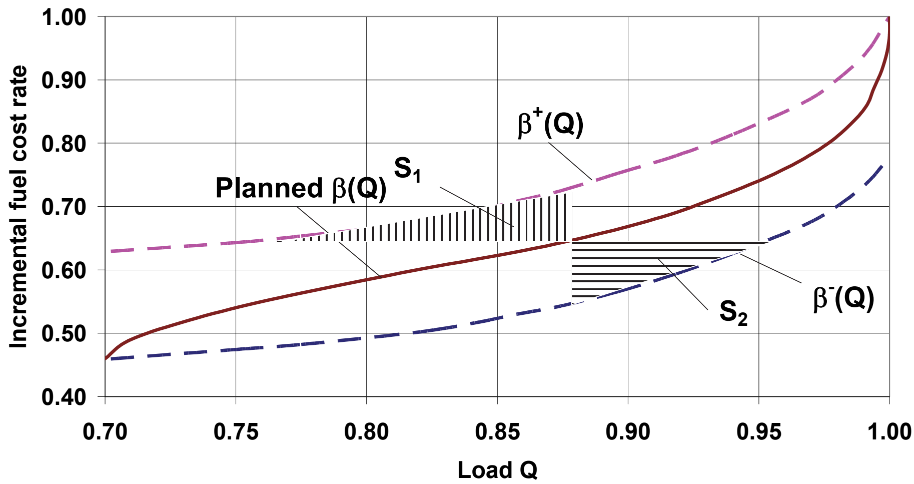

Figure. 6.5. Initial (lower and upper) and planned characteristics of a boiler

After determining the planned characteristics for the min-max task, the common deterministic task of optimization with planned characteristics subject to constraints will be solved. The deterministic equivalent may be solved by ordinary computer programs and methods, which have been elaborated for solution of deterministic optimal scheduling problems in thermal power plants.

6.6. Conclusions

The methodology described above was realized in a complex program at Tallinn University of Technology. The modules for state optimization enable computation of the planned input-output characteristics of power units under probabilistic and uncertain information and solution of the optimization problem in power plants. The program may be used as a supplement for existing software.

The methodology described here enables a rather simple use of probabilistic and uncertain information in optimal dispatching of power plants. The method of planned characteristics is also used in the software for optimal scheduling of power generation at the power system level.

SUMMARY

TSOs are responsible for providing reliable system operation, and power system planning has the key role in that. Therefore, a TSO must systematically analyze system behavior during disturbances in various system configurations during long term and short term planning. Adequate power system models are needed for system analysis. Furthermore, for system stability studies, modelling the generator and its auxiliary systems is the most important task. Generators are the source of active power, providing voltage support, oscillation damping and also frequency regulation.

1. Generator part

In this thesis are discussed generator models both for simplified generator modelling and for detailed generator modelling. The simplified generator model does not enable analysis of all stability phenomena. Considering all the shortcomings of the simplified generator model, it is recommended to model Estonian power system generators by using detailed generator models, which take into account all generator auxiliary system controls. It is recommended that all generators, which are electrically close to the Estonian power system should be also modeled by using a detailed generator model. That means that all the generators in Latvian, Lithuanian, Belorussian, Kaliningrad, Smolenski NPP, Leningradskaja NPP, and large thermal power plants located in Leningradskaja region are recommended to be modeled by using the detailed generator model. Only the generators located far away could be modeled by the simplified generator model.

2. Excitation system

A new model is proposed for the AC machine excitation systems in the Eesti and Balti Power Plant units with pulverized fire boilers. Static excitation system model is also presented. These models can be used in the PSS/E software. Since AC machine excitation systems have no standard model in the PSS/E library, a block diagram of the AC machine excitation system is proposed that allows modelling of that excitation system in the PSS/E supplementary software GMB and use in the PSS/E. In addition, model settings both for AC machine and static excitation systems are presented. AC machine excitation systems currently used in the Balti and Eesti Power Plant are ineffective in terms of dynamic stability provision. Therefore, the dynamic stability of the Estonian power system can be improved by replacing the existing AC machine excitation systems with modern static excitation systems.

3. Governor system

Two models for modelling the governor systems of the Eesti and Balti Power Plant are TGOV1 and IEEG1. TGOV1 is not commonly used because it is too simple, but it is a good starting point. IEEEG1 is more common to model a steam turbine governor system. Both proved to be adequate for modelling the governor systems of the Eesti and Balti Power Plant.

4. Frequency regulation

Frequency regulation principles are introduced. On the basis of the isolation test of 3-4 April 2009, the frequency regulation quality of the Estonian power system was analyzed during fast and slow changes in the power system operation. It can be concluded that the frequency regulation quality of the Estonian power system is adequate and frequency deviation does not exceed 50 ± 0.2 Hz.

5. Optimization of load dispatch between power units and boilers.

A practical methodology is proposed which takes into account probability and uncertainty of initial information. Uncertainty methodology is based on the min-max criterion, which enables the uncertainty of uncontrollable factors to be considered and the maximum possible economic loss caused by uncertainty to be minimized.

6. Further areas to be studied

- Replacement of Soviet made speed governor systems should be investigated considering the fact that in the future stricter frequency regulation requirements of the Estonian power system may be set up. For example, it may happen when the Estonian power system is interconnected to the European power system. Also, replacement of AC machine excitation system should be further investigated for the possible Estonian and European power system interconnection.
- It is necessary to focus on the replacement of Soviet-made excitation systems to modern excitation systems since the power system has undergone significant changes since the AC machine excitation systems were introduced in the power plants. Since 2014 the Estonian power system is connected with the Nordel power system via two HVDC lines with a total capacity of 1000 MW. The first reactor of the Ignalina NPP was closed in December 2004 and the second reactor was closed in December 2009. As a result, Lithuanian power system turned from an energy exporter to an energy importer. The situation where Lithuanian and Latvian power system imports are mostly covered by Russian exports would make Lithuanian and Latvian support for dynamic stability weaker.
- Replacement of Soviet-made speed governor systems to modern ones should be investigated taking into account that currently the Estonian TSO is responsible for keeping one hour's active power imbalance within the range of ± 30 MWh and it is technically approved to interconnect 900 MW of wind parks into the Estonian power system [64].
- It is very important to verify the generator, excitation and governor system model settings. The model settings of the governor system can be verified by using the isolation test results of the Estonian power system from 3-4 April 2009. To verify the generator and excitation system model settings it is necessary to make tests in the power plants to measure essential parameters.

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ABSTRACT

Modelling of control systems and optimal operation of power units in thermal power plants

The main aim of the thesis is to propose models for the Eesti and the Balti Power Plant generators and their auxiliary systems. The models enable studies of stability phenomena in the Estonian power system during different disturbances and transmission network configurations.

The necessity to model the Eesti and the Balti Power Plant generators and their auxiliary system is derived from the reason that the Estonian power system has been changed significantly since the AC machine excitation systems were established. Also, 1000 MW transmission capacity between Estonian and Finnish power systems, opening of the power market in the Baltic countries and the closing of Ignalina nuclear power plant have changed power flows in the Estonian power system and are directly influencing the number of units working.

Operational unit number in the power plants has also changed. In the Balti Power Plant from 12 units 9 units have already been decommissioned and in the near future another 2 units will be decommissioned. In addition, 3 units out of the 8 units in the Eesti power plant will work less than 17500 hours between 2016–2023, which will be followed by closing. These and other changes have impact on the reliability of the Estonian power system. Thus, studies here are required and the proposed models enable further research.

In the Balti and Eesti Power Plants both Soviet-made and modern excitation systems are used. The proposed models enable analysis of a necessity to change old excitation systems to modern ones, considering the need to ensure power system reliability.

Also, the frequency regulation quality of the Estonian power system was analyzed. The analysis was based on the isolation test of the Estonian power system performed on 3-4 April 2009. Currently, Estonian TSO is responsible for keeping one hour's active power imbalance in the range of ± 30 MWh. Today it is only a regulated responsibility for the Estonian power system to participate in the frequency regulation. In the foreseeable future, it is probable that the frequency regulation requirements for the Estonian power system will be set at a more stringent level than is required today. This is likely to occur, for instance, in case frequency regulation principles change between Estonian and Russian TSOs, or if the Estonian power system is linked to the European power systems.

This thesis also addresses the input and output characteristics of oil shale boilers that are changing significantly over the time. A practical methodology is proposed, which takes into account probability and uncertainty of initial information. Uncertainty methodology is based on the min-max criterion, which enables the uncertainty of uncontrollable factors to be taken into account and the maximum possible economic loss caused by uncertainty to be minimized.

KOKKUVÕTE

Energiaplokkide juhtimissüsteemide modelleerimine ja talitluse optimeerimine soojuseelektrijaamades

Käesoleva töö eesmärgiks on välja pakkuda mudelid Eesti ja Balti elektrijaama generaatoritele ja nende juhtimissüsteemidele. Need mudelid võimaldavad teostada Eesti elektrisüsteemi stabiilsuse analüüse erinevate häiringute ning erinevate võrgu konfiguratsioonide korral. Selles töös väljapakutud mudeleid saab kasutada PSS/E tarkvaras.

Eesti EJ ja Balti EJ generaatorite ning nende abisüsteemide modelleerimise vajaduse tingib esiteks see, et Eesti elektrisüsteem on palju muutunud ajast, kui vahelduvvoolu masina ergutussüsteemid on jaamades tööle rakendatud. Samuti 1000 MW ülekandevõimsuse avamine Eesti ja Soome vahel, Balti riikides energiaturu avanemine ja Ignalina TEJ sulgemine on muutnud võimsusvooge Eesti elektrisüsteemis ning otseselt mõjutab töötavate Eesti elektrijaamade koosseisu nii lühiajalises kui ka pikaajalises vaates. Tõenäoliselt on Eesti elektrisüsteem muutumas ka tulevikus. Jaamade koosseis on muutunud. Balti EJ 12 plokist on juba praegu kinni pandud 9 ja lähitulevikus pannakse kinni veel 2. Samuti Eesti EJ 8 plokist 3 plokki töötavad aastatel 2016–2023 mitte rohkem kui 17500 tundi. Nende ja ka teiste muudatuste mõju Eesti elektrisüsteemi varustuskindlusele on vaja tulevikus veel täiendavalt analüüsida.

Balti ja Eesti elektrijaamades on kasutusel nii moodsad Lääne kui ka Nõukogude Liidu aegsed ergutussüsteemid. Antud töös välja pakutud mudelid võimaldavad analüüsida vanade seadmete vahetamise vajadust, lähtudes varustuskindluse tagamise kohustusest.

Samuti vaadeldakse antud töös sageduse reguleerimise võimalusi, analüüsides seda Eesti EJ 2009. aasta eralduskatse näitel. Hetkel kehtivate nõuete järgi Eesti elektrisüsteemi sageduse reguleerimise kohustus piirdub vahelduvvoolu saldo ebabilansi hoidmises iga tund ±30 MWh aknas. Antud kohustuse on Eesti enda peale võtnud BRELLi koostöö raames. Tulevikus sageduse reguleerimise nõuded Eesti elektrisüsteemile võivad muutuda. Muutuda võivad sageduse reguleerimise kohustused, mis on Eesti poolt võetud BRELLi koostöö raames. Samuti võivad muutuda sageduse reguleerimise kohustused, kui Eesti elektrisüsteem peaks liituma sünkroonselt Euroopa elektrisüsteemiga.

Töös näidatakse ka, et põlevkivikatla sisendid ja väljund muutuvad ajas märkimisväärselt ja, et soovituslik on kasutada optimaalse võimsuse jagunemise metodoloogias ebamäärast ja tõenäosuslikku lähenemist. Pakutakse välja ka praktiline metodoloogia, kuidas tõenäosuslikku ja ebamäärast informatsiooni kasutada plokkide vahel võimsuse jagunemise majanduslikuks optimeerimiseks. Metodoloogia aluseks on minmax kriteerium ja selle alusel on välja pakutud minmax optimeerimismudel. Minmax optimeerimismudel võimaldab arvesse võtta erinevate faktorite määramatust ja minimeerida maksimaalset kahjumit, mis tuleneb tuleviku määramatusest.

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Eesti	Emakeel
Inglise	Kõrgtase
Vene	Kõrgtase

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2. Education

Educational institution	Graduation year	Education (field of study/degree)
Narva Estonian High School	1997	Secondary education
Tallinn University of Technology	2001	Electrical Power Engineering, Bachelor of Science in Engineering
Aalborgi University	1999	One semester lectures completed, Master of Science in Environmental Management
Tallinn University of Technology	2003	Electrical Power Engineering, Master of Science in Engineering

3. Language competence/skills (fluent, average, basic skills)

Language	Level
Estonian	Native language
English	Fluent
Russian	Fluent

4. Special course

Period	Subject of special course	Educational or other organization
2001	Short term planning	VIPKenergo, Moscow
2002	Protection in Transmission Networks	Sankt – Peterburg Power Engineering Institute
2003	Protection in Transmission Networks	ABB University Switzerland
2003	Power System Stability and Control	ABB University Sweden
2004	PSS/E – Introduction to Dynamic Simulation	Shaw Power Technologies, USA

5. Professional employment

Period	Organization	Position
1999-2000	Elering AS	Engineer, Maintenance
2000	Elering AS	Power Network Analyst, System development
2000-2001	Elering AS	Power Network Analyst, System operation
2001-2007	Elering AS	Power Network Analyst, System development
2007-2011	Elering AS	Head of operational planning unit, System operation
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2013-	Eesti Energia AS	Strategy development project manager, Strategy Management

PAPER I

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EXCITATION SYSTEM MODELS OF GENERATORS OF BALTI AND EESTI POWER PLANTS

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This paper describes the requirements for the generator's excitation system. Different parts of the excitation system are also presented. Two totally different types of excitation systems are installed in generators of both Eesti and Balti power plants. The one – fast static excitation system UNITROL5000 produced by ABB – was installed in 2005. The other is a rather slow excitation system – high-frequency AC machine – produced in Russia in the middle of the 70s. The paper presents main structures of those excitation systems and their control systems and also proposes models of control systems for dynamic calculations of those systems.

Introduction

Balti and Eesti power plants are two world's biggest power plants working on oil shale. With generation capacities of 765 MW and 1615 MW those plants produce approximately 95% of Estonia's power consumption. Renovation of one power unit at both power plant was completed in 2005. During the renovation new boilers were built, turbines and generators were renovated, and control systems of the power units were also renewed. The total capacity of the new units is 430 MW.

Excitation systems of generators in Balti and Eesti power plants were chosen for investigation because their work has the biggest impact on dynamic stability of the Estonian grid. Two totally different types of excitation systems are simultaneously used at Eesti and Balti power plants. A rather slow high-frequency AC machine excitation system (P-system) produced in Russia in the middle of the 70s is in use, and a fast static excitation system (PD-system) UNITROL5000 produced by ABB was installed in 2005. As the two excitation systems are used in both power plants, the models for dynamic calculations proposed in this paper can be

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used in both power plants as well. Both types of excitation systems have been investigated. The static excitation system UNITROL5000 produced by ABB and used in one 253-MVA generator of Balti Power Plant and in one 253-MVA generator of Eesti Power Plant was studied first followed by studies on the Russian type of high-frequency AC machine excitation system which is used in three 200-MVA generators of Balti Power Plant and in seven 200-MVA generators of Eesti Power Plant.

The basic function of an excitation system is to provide direct current to the field winding of the synchronous machine. The protective functions ensure that capability limits of the synchronous machine, excitation system, and other equipment are not exceeded.

The excitation system also performs control and protective functions important for satisfactory performance of the power system by controlling the field voltage and by that the field current. The control functions include the control over voltage and reactive power flow, and the enhancement of system stability.

Requirements for reliable performance of the excitation system have to be determined considering both the synchronous generator and the power system. The basic requirement is that the excitation system supplies and automatically adjusts field current of the synchronous generator to maintain terminal voltage as the output varies within the continuous capability of generator's U-curves. Margins for temperature variations, component failures, emergency overrating, etc. must be factored in when the steady-state power rating is determined. Usually, the exciter's rating varies from 2.0 to 3.5 kW/MVA generator's rating [2].

The excitation system must also be able to respond to transient disturbances by field forcing consistent with instantaneous and short-term capabilities of the generator. Considering this, there are many factors that limit generator capabilities: rotor insulation failure caused by high field voltage, rotor heating caused by high field current, stator heating due to high armature current loading, core end heating during under-excited operation, and heating caused by high excess flux (volts/Hz). There are time-dependent characteristics of thermal limits, and the short-term overload capability of generators that may be measured from 15 up to 60 seconds. To secure the best use of the excitation system, it should be able to meet the system requirements by taking full advantage of short-term capabilities of the generators without surpassing their limits.

As for the power system, effective control of voltage and enhancement of system stability should be supported by the excitation system. It should be able to respond rapidly to a disturbance improving transient stability modulating the generator field to improve small-signal stability. In addition to the error signal of terminal voltage, modern excitation systems are using auxiliary stabilizing signals (power system stabilizer) to control the field voltage to damp system oscillations. Modern excitation systems with high ceiling voltages are capable of providing practically instant response.

A substantial improvement of dynamic performance of the overall system can be achieved by combination of high field-forcing capability with the use of auxiliary stabilizing signals.

Exciter. It provides dc power to the field winding of the synchronous machine. Exciter can be either an AC machine, DC machine, or it is fed from generator's terminal switchgear through converter.

Regulator. It processes and amplifies input control signals to a level and form appropriate for control of the exciter. This includes both regulating and stabilizing the functions of the excitation system (rate feedback or lead-lag compensation).

Protective circuits and limiters. They include a wide range of control and protective functions to guarantee that the capability limits of exciters and synchronous generator are not exceeded. Limitation of maximum excitation, terminal voltage, field-current and underexcitation, regulation and protection of volts-per-hertz ratio are some of the principal functions. These circuits are usually distinct ones, and their output signals may be applied to the excitation system at different locations as a summing input or a gated input. In Fig. 1 they are grouped and shown as a single block for better consideration.

Load compensation and terminal voltage transducer. Terminal voltage transducer senses generator's terminal voltage, rectifies and filters it to dc quantity, and compares it with a reference which represents the desired terminal voltage. If it is desired to hold constant voltage at some point electrically remote from the generator's terminal, load (or line-drop, or reactive) compensation may be also provided. Load compensation function is optional, and at Eesti and Balti power plants it is used in UNITROL5000, but it is not used in the Russian high-frequency AC machine excitation system.

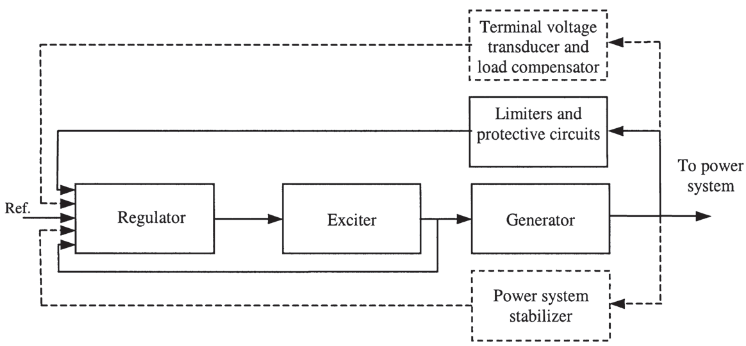

Fig. 1. Functional block diagram of the control system of a synchronous generator's excitation.

Power system stabilizer (PSS). Its function is optional as well. It is not used in the Russian high-frequency AC machine excitation system, but it is used in UNITROL5000. PSS is used to add modulation signal to the regulator to damp power system oscillations. Some commonly used input signals are rotor speed deviation, electrical or accelerating power and frequency deviation.

Methodology

The excitation system should be considered from the aspect of classical control methodology. A classical control methodology is based on feedback and error-driven control.

Simple systems are usually one-dimensional that means one input signal and one output signal. In that case the dependence of controlled object state on output is easily describable by a relatively simple function hence these systems could be successfully controlled by the output signal. The aim of regulation is automatic stabilization of the output, changing it by a given or by some unknown (stochastic, fuzzy) principle. These systems are called stabilizing and control systems.

Simple systems can be controlled by two principles. The first principle is that regulation action is dependent on regulation error, this action uses feedback for regulation, hence it is called feedback control. The second principle is that the regulation action is made in a way that compensates disturbance influences. Usually a combination of both principles is used, and in this case regulation action is a function of regulation error and disturbance compensation. Disturbance compensation principle is distinguishable from feedback principle only with some simplification, because generally measured disturbances can also be viewed as output of the controlled object, and feedback can also be used for regulation.

Controlled object is always of a specific structure. Technical and technological regulation objects are the objects consisting of controlled operation and measurement equipment. Measuring equipments give information about working of the controlled object. Regulator compares design state of the object with its actual state and makes regulation actions.

In the case of the excitation system, the generator is the controlled object, and controlled operation is the control of generator's acceleration. An excitation system uses both above-mentioned principles: regulation error and disturbance compensation. Representation of excitation systems by automation block diagrams is necessary for making accurate dynamic calculations and also in the case if the software model library used at calculations does not contain the required model. Software programs of dynamic calculations such as PSSE and PSCAD used at Estonian TSO and at Tallinn University of Technology do not contain the models of equipment produced in Russia.

PSSE and PSCAD offer the possibility to model excitation system by automation blocks.

Models of excitation systems

Static excitation system UNITROL5000, as mentioned above, is used in one 253-MVA generator of Balti Power Plant and in one 253-MVA machine of Eesti Power Plant. According to the information from ABB [9], static excitation system UNITROL5000 has the following functions:

- Voltage regulator with PID filter (AUTO operating mode);
- Field current regulator with PI filter (MAN operating mode);
- Reactive load and/or active load droop/compensation;
- Limiters for:
  - Maximum and minimum field current
  - Maximum stator current (lead/lag)
  - P/Q under excitation
  - Voltage-per-hertz characteristics.
- Power factor/reactive load regulation;
- Power system stabilizer (PSS)
  - conventional in accordance with IEEE-PSS2A
  - Adaptive power system stabilizer
  - Multiband power system stabilizer.

All components in these systems are static. The excitation power is supplied through a transformer from the station auxiliary bus, and it is regulated by a controlled rectifier. This type of the excitation system is also commonly known as a bus-fed or transformer-fed static system (see Fig. 2).

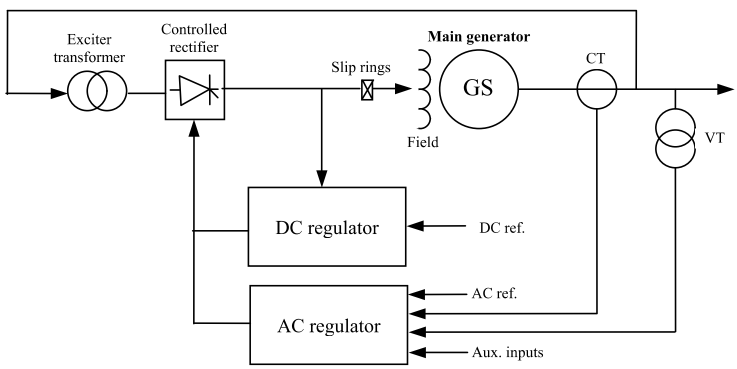

Fig. 2. Scheme of the static excitation system.

The inherent time constant in this system is very small. The maximum output voltage of the exciter (ceiling voltage) depends on the input ac voltage. It means that in system-fault conditions causing depressed terminal voltage of the generator, the available ceiling voltage of the exciter is reduced. This limitation of the excitation system is mainly offset by its virtually instant response and high post-fault field-forcing ability. Big generators that are using such type of the excitation system perform satisfactory when they are connected to a large power system. However, this excitation system is not performing as expected if the generator is connected to a small industrial network with long fault-clearing time. The automation block diagram of the exciter system UNITROL is shown in Fig. 3.

There are following marks in Fig. 3: KIR – compensation factor of reactive power, KIA – compensation factor of active power, KR – steady-state gain, TB1 – the first lag-time constant of controller, TB2 – the second lag-time constant of controller, TC1 – the first lead-time constant of controller, TC2 – the second lead-time constant of controller, Up+ , Up- – AVR positive and negative ceiling values of the output, respectively.

As one can see, the excitation system UNITROL5000 also includes the function of power system stabilizer (PSS). PSS is made in accordance with IEEE – PSS2A standard. The PSSE standard dynamic library contains this type of PSS models (see Fig. 4). In the PSSE model library this model is called Dual-Input Stabilizer model. PSS uses auxiliary stabilizing signals to add damping to the generator's rotor oscillation by controlling its excitation. Some commonly used input signals are rotor speed deviation, accelerating power and frequency deviation. It is an effective way to increase small signal stability performance.

There are following marks in Fig. 4: input signal V1 corresponds to the filtered value of deviation from rotor angular frequency $\Delta\omega$, V2 – filtered value of electric power at generator terminals, TW1-TW4 – wash-out time constants, Ks1 – PSS gain factor, Ks2 – compensation factor for calculation of integral of electric power, Ks3 – signal matching factor, T1 – T4 – lead-time constants of conditioning network, T7 – time constant for integral of electric power calculation, T8, T9 – time constant of ramp-tracing filter, M, N – degree of ramp-tracing filter, UST_{max}, UST_{min} – upper and lower limit of stabilizing signal, respectively.

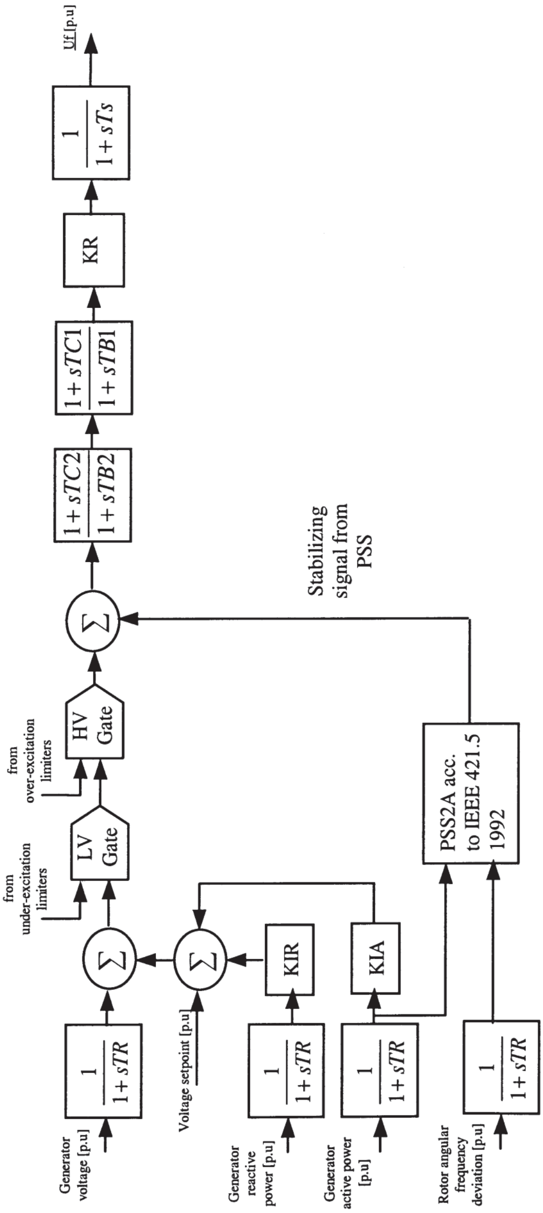

Fig. 3. Block diagram of automation of the exciter UNITROL5000 [9].

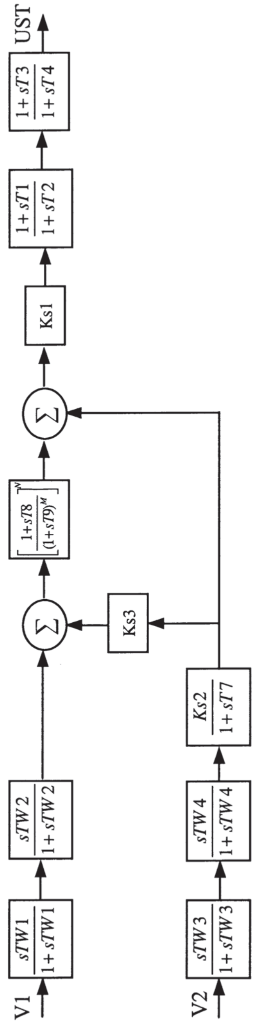

Fig. 4. Block diagram of automation of the power system stabilizer UNITROL5000 [9].

Russian type of high frequency AC machine excitation system

The other exciter type used at Eesti and Balti power plants is ВГТ-2700-500, and regulator type is ЭПА-325. It is an old version of the Russian excitation system. In this type of the excitation system the exciter is high-frequency (500 Hz) induction AC generator, which is placed in the same shaft with the main generator. The principle scheme of this exciter system is shown in Fig. 5.

The exciter has three windings: W1 is used as the main excitation winding and it is connected serially with generator's rotor winding, W2 is used to excite the forcing system, and W3 is used to give an additional excitation while the exciter is overexcited. The regulator has two electromagnetic magnifiers which are connected in series. The one is used to lead exciter's forcing winding, and the other to lead exciter's main winding. The structure of both magnifiers is similar, and they have three leading windings with the following functions:

1. Excitation-forcing limiter;
2. Magnifier core for additional pre-magnetization;
3. Flexible feedback, which gets its power from stabilizing transformer.

Block diagram of automation of the high-frequency AC machine excitation system is given in Fig. 6.

The exciter is lead by magnifiers, and because of that inherent time constant of the excitation system is rather big. Therefore these kinds of excitation systems are called slow-response excitation systems (P-system).

There are following marks in Fig. 6: TR – time constant of measuring filter, Te – gate control unit and time constant of converter, Tv – time constant of amplifier, Kv – amplification factor of amplifier, Ke – amplification factor of exciter, Te – time constant of exciter, Kffb – amplification factor of flexible feedback, Tffb – time constant of flexible feedback, Krfb – amplification factor of rigid feedback, Kf – amplification factor of winding W1, K – amplification factor.

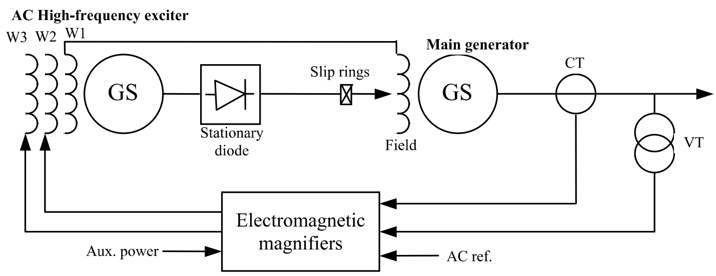

Fig. 5. Excitation system of the high-frequency AC machine.

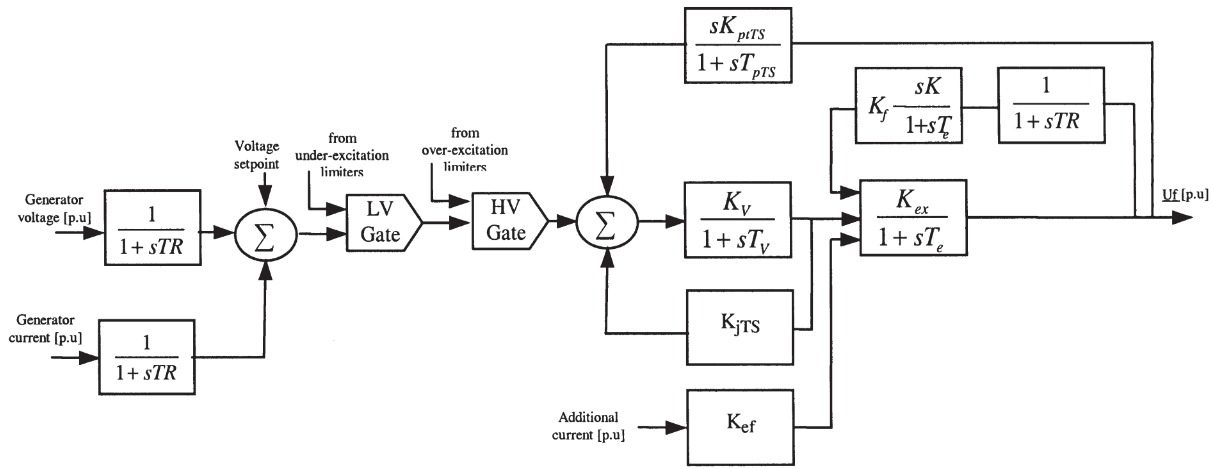

Fig. 6. Block diagram of automation of the high-frequency AC machine excitation system.

Conclusions

In this paper two totally different excitation systems have been investigated. One of them is an old Russian-type high-frequency AC machine excitation system which was developed in the 60s and installed in the 70s into two major power plants in Estonia. The other is a modern static excitation system, which was installed in 2005 only in two blocks of the above-mentioned power plants. This paper describes the requirements for the excitation system. Both systems satisfy the basic requirements, but because of their different structure their responses to grid disturbances are of different strength. Automation block diagrams needed for dynamic calculation programs are proposed.

Acknowledgements

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PAPER II

H. Tammoja, **R. Attikas,** J. Shuvalova. Calculation of input-output characteristics of power units under incomplete information. Oil Shale, 2007, Vol. 24, No. 2 Special, pp. 277-284. Estonia Academy Publishers ISSN 0208-189X

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CALCULATION OF INPUT-OUTPUT CHARACTERISTICS OF POWER UNITS UNDER INCOMPLETE INFORMATION

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Optimal operation of power plants, electrical networks and power systems is a most important issue in conditions of the electricity market. There are many unsolved problems in the field of optimal operation of power systems and power plants which are usually tackled as deterministic ones. Actually the initial information is never complete. The information may be in several forms: probabilistic, uncertain and fuzzy. This paper presents the principles of optimum dispatch of thermal and electrical power between boilers and power units in power plants under incomplete information.

Introduction

This paper presents the principles for calculation of input-output characteristics of power units under incomplete information. The problem of computation of optimum schedules for active power generation in a power plant for a certain time period (day, week) is one of relevant optimization assignments in power plant control. Input-output characteristics of power units are the most important initial data for solving this task. Usually this problem is tackled as a deterministic one at which the objective function, constraints and uncontrollable factors are single-valued [1]. Actually the initial information is never complete. Neglect of these circumstances decreases the efficiency of optimization. Therefore, it is necessary to elaborate optimization methods of power plant state, which consider the actual incompleteness of the initial information. This paper describes a method which takes into account probabilistic and uncertain information.

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The initial mathematical model of a power unit

The input-output characteristic of a condensing unit can be presented as a composite function

$$C = cB(Q_T(P)) = C(P), \tag{1}$$

where

c – price of fuel;
C– fuel cost of the unit;
P– power output of the unit;
$B(Q_B)$ – input-output characteristic of a boiler, assuming that $Q_B = Q_T$;
Q_T – heat input of the turbine;
$Q_T(P)$ – input-output characteristic of the condensing turbine;
$C(P)$ – input-output characteristic of the condensing unit.

Cost functions of condensing power units are usually continuous, piecewise smooth and strictly convex.

The most important characteristic for solving the problem of optimum dispatch in a power plant is the characteristic of incremental cost rate:

$$\beta = \frac{dC(P)}{dP}. \tag{2}$$

If a power unit consists of a turbine and two boilers (double unit), the optimisation of a power unit control means optimal dispatching of thermal power of two boilers at turbine input. In Estonia, all oil-shale power units are double units.

Input-output characteristics of boilers and power units depend on lots of parameters, which are characterized by random deviations from their nominal or planned values.

For solution of optimal load dispatch in a power plant under incomplete information, the method of planned characteristics may be used [2, 3].

Computation of optimal load dispatch in a power plant under the probabilistic or uncertain information consists of two stages:

1. Computation of planned characteristics of power units and construction of deterministic equivalents.
2. Solution of deterministic equivalents.

Some results of statistical analysis of state parameters of power units and boilers

During many years the probabilistic characteristics of boiler's state parameters, boiler's load and power units' loads have been analysed in Estonian power plants. The fuel used in Estonian condensing power plants is oil shale. The effectiveness and reliability of oil shale-fired power plants depends on oil shale quality, especially on its heating value. The average heating value of oil shale consumed by power plants depends on the quality and quantity of the fuel supplied by mines and opencasts and has been changing over the years. Some results of statistical analyses of deviations of oil shale parameters in Estonian power plants are shown in Table 1 [5].

The results of statistical analysis of deviations in state parameters of power units and boilers are shown in Table 2.

Table 1. **The results of statistical analysis of oil shale parameters in Estonian power plants**

Parameter	Minimal value	Maximal value	Coefficient of asymmetry	Root-mean-square, %
Heating value, MJ/kg	9.8	13.2	0.02–0.14	0.25–0.45
Moisture content, %	11.3	13.3	0.11–0.64	0.29–0.39
Ash content, %	47.7	51.6	–0.2–0.03	0.22–0.37

Table 2. **The results of statistical analysis of deviations in turbine and boiler parameters**

Parameter	Mathematical expectation, %	Root-mean-square, %	Coefficient of asymmetry
Steam pressure	–5.8…–5.6	4.71–4.93	–2.4–1.51
Steam temperature	–5–3	1.11–2.36	–1.27…–0.25
Flue gas temperature	3.4–7.0	3.6–5.0	–2–2
Excess-air coefficient	5–6	0.14–0.19	0.23–1.03
Feed-water temperature	–1–15	4–6	–2…–1

Computation of planned characteristics under probabilistic information

Let us assume that all initial functions (characteristics of power units, of boilers and of auxiliary power) and uncontrollable parameters are random functions and variables, the initial information on which is available in probabilistic form. Input-output characteristics of boilers depend on flue gas temperature after the boiler, fuel parameters, etc. Turbine characteristics depend on vacuum in the condenser, steam pressure and temperature at the inlet of the turbine, etc. All these parameters are random. On the basis of probabilistic information, it is possible to calculate new characteristics of boiler and turbine by the following formulas [6]:

Boiler:

$$C_B(Q_B) = C_B(Q_B, m_{X1}, ..., m_{Xn}) + \frac{1}{2}\sum \frac{\partial^2 C_{Bj}(X)}{\partial X_j^2}\sigma_{Xj} + \frac{1}{2}\sum_{k=1}^{n}\sum_{j=1}^{n}\frac{\partial^2 C_B(X)}{\partial X_k \partial X_j}\cdot k_{Xk}k_{Xj} \tag{3}$$

Turbine:

$$Q_T(P) = Q_T(P, m_{X1}, ..., m_{Xn}) + \frac{1}{2}\sum \frac{\partial^2 Q_T(X)}{\partial X_j^2}\sigma_{Xj}\,, \qquad (4)$$

where

m – mathematical expectations of parameters;

σ – root-mean-square of parameters.

These characteristics are the first-degree planned characteristics of units.

Figure 3 shows the planned incremental cost rate characteristics of a power unit.

If necessary, the planned cost rate and planned input-output characteristics of units can be calculated.

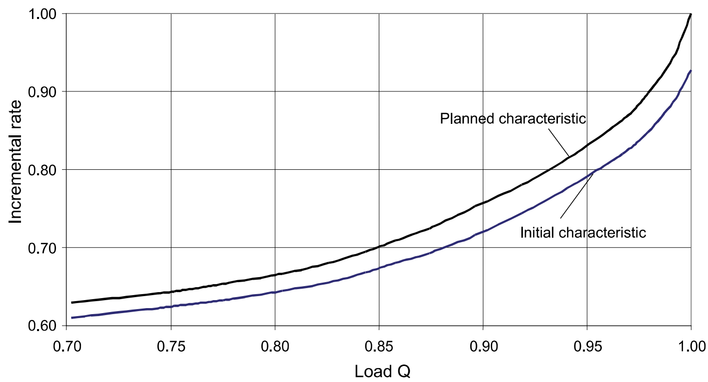

Fig. 1. Initial and planned characteristics of the boiler.

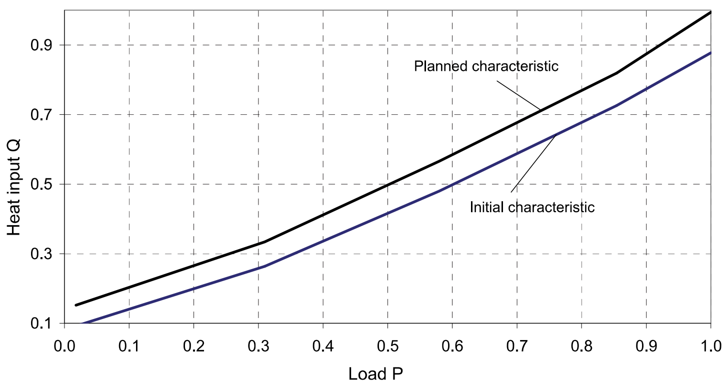

Fig. 2. Initial and planned characteristics of the turbine.

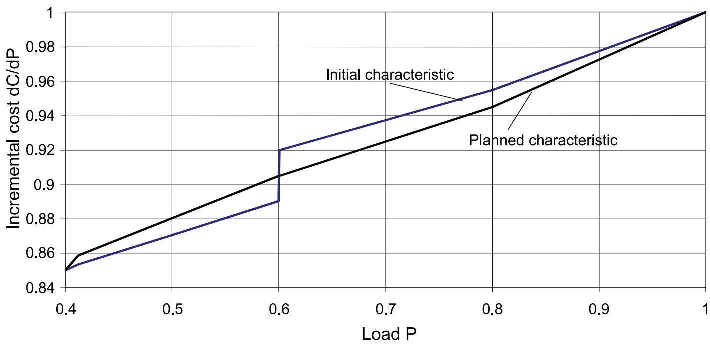

Fig. 3. Initial and planned incremental cost rate characteristics (in relative units) of the power unit.

Computation of planned characteristics under uncertain information

In this paper the uncertainty of information means that only intervals of values of functions (input-output characteristics) are given, not their concrete values. The values of functions at given intervals are uncertainties.

The first step in calculating the planned characteristics is the calculation of initial lower and upper incremental cost rate characteristics of power units.

The lower characteristic must be determined as a characteristic in the case of which all the operation parameters of the power unit are on the best level, and the upper characteristic – the one in the case of which all the operation parameters are on the worst level. For example: the worst fuel, the worst vacuum in the condenser, the worst state of furnaces of boilers and so on.

The lower characteristic of the power unit may be calculated by the formula

$$\beta^{-}(P) = \beta(P) - \sum k_i \cdot \Delta X_i^{-} , \tag{5}$$

where

$\beta(P)$ – initial characteristic of the incremental cost rate of the power unit;
k_i – correction coefficient of operation parameter deviation;
ΔX_i^{-} – deviation of operation parameter towards the direction which reduces the incremental cost rate of the power unit.

The upper characteristic of the power unit may be calculated by the formula

$$\beta^{+}(P) = \beta(P) + \sum k_i \cdot \Delta X_i^{+} , \tag{6}$$

where

ΔX_i^+ – deviation of operation parameter towards the direction which increases the incremental cost rate of the power unit.

The deviations of operation parameters in the oil shale power units are considerable.

The calculations show that the zone of uncertainty of incremental cost rate characteristics is about 10% in boilers, about 7% in turbines, and up to 20% in power units.

The min-max planned characteristics can be calculated by various approximate methods [3, 4].

The simplest method for calculation of min-max planned characteristics is as follows.

1. Choose different values of incremental cost rate of a power plant.
2. Calculate the min-max load distribution by chosen values of incremental cost rates.

Min-max incremental fuel cost characteristic of a boiler is shown in Fig. 4. The point of the planned incremental cost characteristic $\beta(\bar{P})$ is found on condition that $S_1 = S_2$.

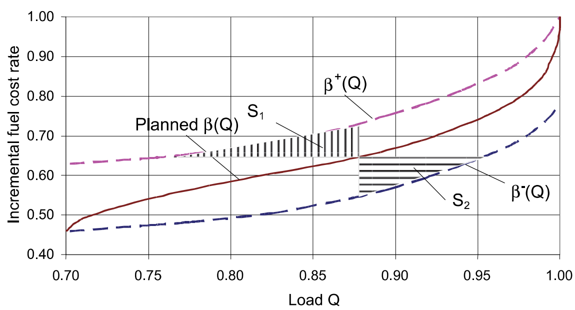

Fig. 4. Initial (lower and upper) and planned characteristics of a boiler.

Figure 5 shows the planned incremental fuel cost rate characteristic of a power unit.

After determining the planned characteristics for min-max task, the common deterministic task of optimization with planned characteristics subject to constraints will be solved.

The deterministic equivalent may be solved by ordinary computer programs and methods, which have been elaborated for solution of deterministic optimal scheduling problems in thermal power plants.

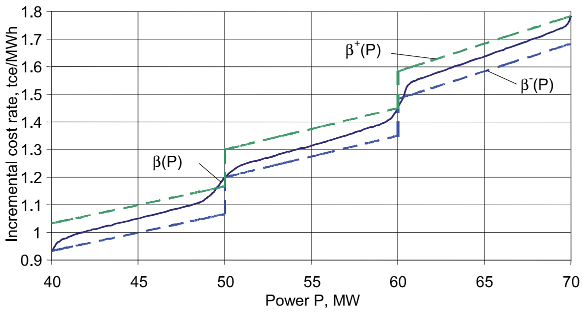

Fig. 5. Initial and planned incremental fuel cost rate characteristics (in relative power units) of a power unit.

Computer programs

The methodology described above was realized in a complex program at Tallinn University of Technology. The modules for state optimization enable to compute planned input-output characteristics of power units under probabilistic and uncertain information and solve the optimization problem in power plants. The program may be used as a supplement for the existing software.

Conclusions

The methodology described here enables a rather simple use of probabilistic and uncertain information in optimal dispatching of power plants. The method of planned characteristics is also used in the software for optimal scheduling of power generation at the power system level.

The optimal load dispatch on the basis of fuzzy information will be our subsequent object of interest.

The method of optimal dispatch in power plants which takes into account the probabilistic information about random factors enables economy of fuel by up to 1.5%.

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PAPER III

V. Medvedeva-Tšernobrivaja , **R. Attikas**, H. Tammoja. Characteristic numbers of primary control in the isolated Estonian power system. Oil Shale, 2011, Vol. 28, No. 1 S, pp. 214–222. Estonia Academy Publishers ISSN 0208-189X

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CHARACTERISTIC NUMBERS OF PRIMARY CONTROL IN THE ISOLATED ESTONIAN POWER SYSTEM

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Characteristic numbers of Primary Control for a small control area of interconnected power systems, such as Estonian Power System, become a major consideration in perturbation's islanding (isolated operating), or in initiating black start situation. Against a background of independence of the transmission system and electricity production towards the recently opened electricity market in Estonia arise the actuality of reliability in the context of the quality of supply (frequency and voltage) and successful parallel operation. Characteristic numbers of Primary Control, such as the network power frequency characteristic, governor droop and load response influence to the frequency regulation process in case of significant frequency deviation. Because of solely dependence on Primary Control executed by IPS central regulator, the limited number of frequency affecting events can be obtained for the reasonable figures. The controlled system separation test is the only opportunity for Estonian Power System that investigates the capability of frequency regulation. Primary Control relates to the supply and load responses that stabilize frequency whenever there is a change in load-resource balance. Based on the methodology suggested by ENTSO-E and local measurements, the study state behavior of Primary Control of the isolated Estonian Power System is described in the case study. The paper presents the characteristic numbers of Primary Control in the isolated system under the system contingencies such as the artificially created failure produced by network or switch-offs of individual generating blocks and switch-offs of the HDVC link.

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Introduction

Estonian Power System, with maximum load approx 1500 MW and national generating capacity during maximum time approx. 2300 MW, like the other power systems in the Baltic States was originally designed as a part of the former Unified Power System of the U.S.S.R. and, therefore, systems of the Baltic States are interconnected with that system. Besides that, Estonian power system is interconnected via a high-voltage direct current (HVDC) transmission link with Finland that is part of the Nordic power system. These interconnections are power corridors for bulk-energy exports and imports to the Baltic power systems. However, the power systems of the Baltic States are solely dependent on IPS/UPS Power System for Primary Control executed by IPS central regulator. The ability to operate isolated and execute the primary control within the system with its own resources to mitigate a frequency deviation will be investigated during the controlled system separation test of Estonian and IPS/UPS Power System. Figure 1 shows the separation scheme. The characteristic numbers of Primary Control evaluated based on the number of data collected during the fast and slow changes in supply with and without utilization of AFC (automatic frequency control) function of HVDC link have been studied and presented.

Primary Control relates to the supply and load responses that stabilize frequency whenever there is a change in the load-resource balance. During the contingency, such as failures produced by network (line openings) or the switch-offs of individual generating blocks and switch-offs of the HDVC link, the frequency changes due to the mismatch in load and generation. The level to which the frequency drops depends on the starting point as well as the system inertia. It is the system inertia, which provides the initial ability of the system to oppose the change in frequency. Physically, it may loosely be defined by the mass of all the synchronous rotating generators and motors

Fig. 1. Separation scheme for the controlled separation test.

connected to the system. If the system inertia is high, the frequency will fall slowly and vice versa, during any system contingency. System inertia is not frequency control per time, but it does influence the time taken for frequency to change after a loss of generation or load. Higher system inertia provides more time to the generator governors to respond to a change in frequency, and hence it is desirable. The system contribution to the frequency variation thus comprises two components namely supply (generators governor response) and load responses [2].

Load response is the reduction in the power consumption in response to a decline in the frequency and occurs simultaneously or with a minimal time lag as the frequency changes. Load frequency response is not a question of consideration of the current case study.

Primary response is the governor response, which occurs within the 3-10 s time frame. The changes in the generator output are in response to the change in frequency and are independent of any command. Generator governor response stabilizes the frequency whenever there is a change in the load-resource balance, but does not restore the frequency to the rated frequency level.

The case study presents the characteristic numbers of Primary Control in the isolated Estonian Power System based on real time data recovered by the SCADA systems and measuring equipments LEM and REMI.

Methodology

The method used to calculate the characteristic numbers of Primary Control in the Estonian Power system context has been adopted from the methodology suggested by ENTSO-E (European Network of Transmission System Operators for Electricity - former UCTE) [1].

The main purpose of this frequency analysis is to estimate the operational reliability of the isolated network.

System contingencies such as the switch-offs of individual generating blocks or failures produced by network (line openings) and switch-offs of the HDVC link have been recovered and analyzed to obtain the characteristic numbers of the isolated Estonian Power System.

The following characteristics are calculated in the case study.

Network power frequency characteristic

The network power frequency characteristic also known as composite frequency response characteristic or the stiffness of the system [4] represents the total action of the primary frequency control provided by generators and the self-regulating effect of the load. The network power frequency characteristic is negative, if the frequency drops, hence the generator output increases. The network power frequency characteristic is positive, if the frequency increases, hence the generator output decreases.

$$\lambda = -\frac{\Delta P}{\Delta f},$$

where:

λ – positive and expressed in MW/Hz,

ΔP – power deviation responsible for the disturbance, the power imbalance,

Δf – quasi-steady-state frequency deviation caused by the disturbance, determined from a "smoothing line" drawn between 10 and 30 seconds.

As any physical value, the frequency goes through a transitory state in response to a perturbation before stabilizing at a new value. The maximum deviation from the target frequency during the transitory period is called the dynamic frequency deviation.

Power-frequency characteristic of units

Power–frequency characteristic of unit also known as the governor droop or droop of generating unit is the characteristic by which a generator governor causes the output of the generator to change in response to a change in frequency. Estonian Grid Code [3] currently requires the governor droop to be set to 2–8%. The droop of a generating unit is an important parameter of primary frequency control. A lower droop increases the response of a unit but would cause more stress in the generating unit as it would react more strongly to each deviation. On the other hand, a unit with a low droop is more likely to succeed in switching to islanded mode in case of a major disturbance and tends to reduce the quasi-steady state frequency deviation following an imbalance.

$$s_G = \frac{-\Delta f / f_n}{\Delta P / P_n},$$

$$\Delta f = f - f_n,$$

where:

ΔP – the variation in active power output of a generator,

Δf – the variation in system frequency,

f_n – rated frequency,

P_n – rated active power output.

The both variations, according to the methodology suggested by ENTSO-E, are defined in the abstract, there are no definitions for f in frequency variation expression and ΔP. Furthermore, the system frequency immediately before disturbance differs from the rated frequency 50 Hz, and there is no necessity to use it in the expression of variation of system frequency. In the case study the following equation was used [5, 7]:

$$\Delta P = P_B - P_A,$$
$$\Delta f = f_B - f_A^{'},$$
$$f_A^{'} = f_A \pm \Delta f_0.$$

P_A – actual active power immediately before disturbance,
P_B – actual active power immediately after disturbance,
Δf – the variation in system frequency,
f'_A – frequency immediately before disturbance,
f_A – actual frequency immediately before disturbance,
Δf_0 – dead band of primary control,
f_B – actual frequency immediately after disturbance.

To avoid the indistinctness in interpretation of time window to be measured, the "Immediately after disturbance" is interpreted in the case study as 30 seconds after disturbance, but "Immediately before disturbance" is still the subject to interpretation.

Case study

A controlled separation test of the Estonian Power System from synchronously connected UPS/IPS grid has been performed in April 2009. The main purpose of separation was to investigate the capability of frequency regulation in isolated Estonian Power System during the fast and slow changing in supply with and without utilization of AFC (automatic frequency control) function of HVDC link. The initial parameters of Estonian Power system were maximum load during the test approx 800 MW and generating capacity approx. 820–725 MW. In separation test thermal power plants generators, smallest one with net capacity about 20 MW and largest one with net capacity 160–190 MW, were attended. Some of the large units worked in half capacity. Only thermal power plants generators had operating governors to respond to frequency deviation and performed Primary Control within the separated system.

The separation test was divided into the five stages:

In the first stage of the separation test EPS was separated from the UPS/IPS grid due to the artificially created failure produced by network (line opening) with a surplus about 72 MW. At the beginning of the test AFC of HVDC link was out of work. In response to the change in the load-resource balance the frequency in the system decreased by Δf = 161 mHz. The droop of large generating units was between 3–6%, droop of small units was 8%. Network power frequency characteristic of the current variation in active power output has been found to be 1056 MW/Hz. The following figures indicate the response of resources to the different failure events. Figure 2 shows the response of the large unit to the failure produced by network.

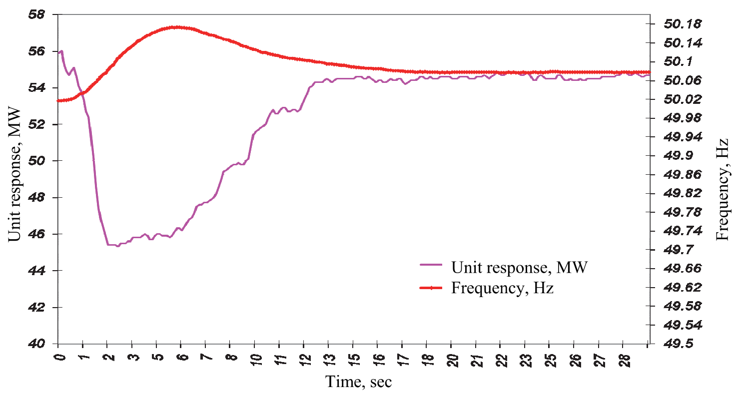

Fig. 2. Response of the large unit to failure produced by network event.

Before the next test stage the supply and load responses stabilize the frequency in the system for 50.01 Hz and AFC of HVDC link was switched on. Unexpectedly the active power flow arised instantly to 73 MW causing shortage in Estonian Power System and frequency droop $\Delta f = 206$ mHz. Thermal units in tandem with AFC of HVDC link stabilized frequency after 30 seconds. The droop of large generating units was between 2–5%, that of small units droop 5%. Network power frequency characteristic the current variation in active power output was 879 MW/Hz.

In the second stage with process duration for 180 seconds change in the output of one large unit from 150 MW to 80 MW was slow. All frequency regulation was done by AFC of HVDC link. Network power frequency characteristic is not considered in context of such disturbance. Figure 3 shows response of large units to slow changes in generation amount within the isolated system.

In the third stage the switch-off of individual generating block with the output of 100 MW was performed. Frequency in the isolated system dropped by $\Delta f = -420$ mHz. In the frequency stabilizing process all the primary regulation recources within the isolated system were attended. The droop of large generating units was between 3–6%, droop of small units was 8%. Network power frequency characteristic for the current variation in active power output was 242 MW/Hz. Figure 4 shows the response of the small unit to generation loss.

In the fourth stage AFC of HVDC link was switched off, and due to that in the isolated power system a deficit about 51 MW occurred, frequency dropped for $\Delta f = -286$ mHz. The droop of large generating units was between 3–6%, droop of small units was 8%. Network power frequency characteristic for the current variation in the active power output was

305 MW/Hz. Figure 5 presents the changes in active power via HVDC link and system frequency in the stage of AFC switch-offs.

In the fifth stage EPS was reconnected with UPS/IPS.

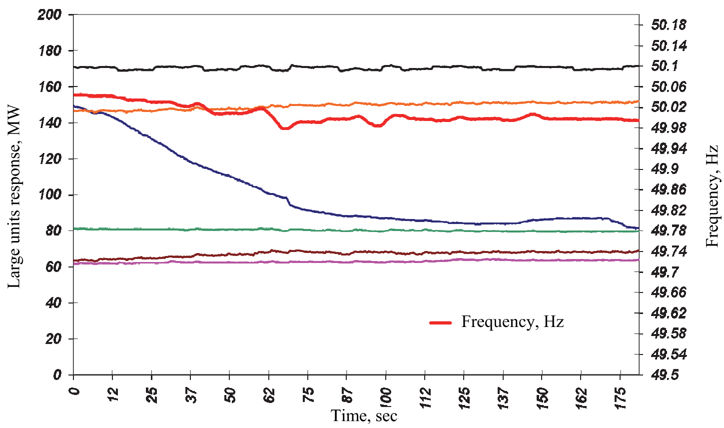

Fig. 3. The response of large units to slow changes in generation amount within the isolated system.

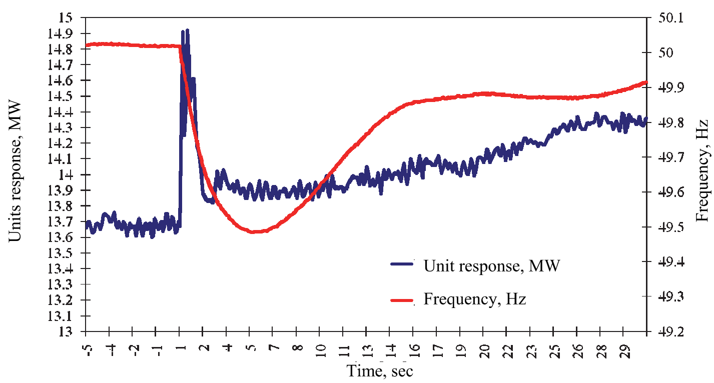

Fig. 4. The small unit response to generation loss event.

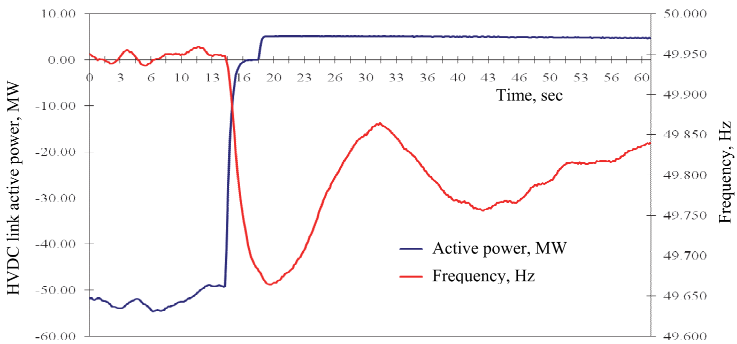

Fig. 5. Changes in active power via HVDC link and system frequency in the stage of AFC switch-offs.

Conclusions

The main purpose of the controlled separation test was to investigate the capability of frequency regulation in isolated Estonian Power System. The system response was adequate to the disturbances, system Primary Control operated properly. Despite that Estonian Grid Code [3] has mandated the requirement of operating governors for all generators for connection to the grid, calculated droops show the requirements for adjustments. From the results obtained, it is evident that the power frequency characteristic of the network is a highly variable parameter and it is difficult to accurately quantify natural response of the system. The common factors affecting the network power frequency characteristic are: system size, frequency at the start of the incident, loading of generators, losses, load consumption, number of generators in service at the time of incident, type of generation, governor action or speed control mode type, time of day and season [5].

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PAPER IV

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Power and Frequency Control Principles of Different European Synchronous Areas

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***Abstract*-This paper presents an overview of power and frequency control principles used in IPS/UPS[1] and ENTSO-E RG CE[2] synchronous areas. Power and frequency control is one of the most important issues that need to be considered for implementing the synchronous interconnection between these two systems, about which it is being talked about for quite long. The paper contrasts IPS/UPS and ENTSO-E RG CE power and frequency control norms and standards and defines the main differences and similarities between them. Finally, the main challenges to interconnect synchronously IPS/UPS and ENTSO-E RG CE systems are also discussed.**

I. Introduction

The Unified Power System of Russia (UPS) consists of 69 regional systems which themselves form 7 Interconnected Power Systems (IPS): IPS East, IPS Siberia, IPS Urals, IPS Middle Volga, IPS South, IPS Centre and IPS North West. UPS is synchronously interconnected with Azerbaijan, Belarus, Georgia, Kazakhstan, Latvia, Lithuania, Moldova, Mongolia, Ukraine and Estonia. Through the power system of Kazakhstan, UPS is synchronously interconnected with Kyrgyzstan's and Uzbekistan's power systems, the two systems of Central Asia [1].

IPS/UPS is the most extended power system in the world. It spans through out 8 time zones. Currently, IPS/UPS system has 337 GW of installed generating capacity and supplies about 1200 TWh to more than 280 million consumers.

The Regional Group Continental Europe comprises the TSOs of the former UCTE[3] synchronous area [2]. It is a system that connects 23 countries of Europe. The main purpose of the Regional Group Continental Europe (RG CE) is to pursue the reliable and efficient operation of the Continental Europe Synchronous Area [2]. At the moment, the ENTSO-E RG CE system has 631 GW of installed generating capacity and supplies electricity to 450 million people with an annual consumption of 2530 TWh.

Currently, the basic normative document that defines the principles of power and frequency control in IPS/UPS is the Standard on Frequency and Active Power Control in UPS and Isolated Systems of Russia (стандарт "Регулирование изолированно работающих энергосистемах России"). The basic document that regulates the main norms and standards of power and frequency control in ENTSO-E RG CE is the Operation Handbook. Therefore these documents have been used as a base for the analysis of similarities and differences between IPS/UPS and ENTSO-E RG CE power and frequency control.

[1] IPS/UPS – Interconnected Power System/ Unified Power System
[2] ENTSO-E RG CE – ENTSO-E Regional Group Continental Europe; ENTSO-E – European Network of Transmission System Operators for Electricity
[3] UCTE – Union for the Co-ordination of Transmission of Electricity

II. Power and Frequency Control Basic Principles

The frequency of a system is dependent on active power balance. As frequency is a common factor throughout the system, a change in active power demand at one point is reflected throughout the system by a change in frequency [3]. The frequency of a system decreases, if active power demand exceeds the generation, and frequency increases, if generation exceeds demand. So, there should be a balance between generation and demand in a system to keep frequency at the set-point value. The maintenace of this balance is the main task of power and frequency control.

Power and frequency control consists of four stages:

1) primary control;
2) secondary control;
3) tertiary control;
4) time control.

The objective of the primary control is to restore the balance between generation and demand after a disturbance or incident occured in a power system, using turbine governors. Primary control stabilises the system frequency, activating primary reserve during a few seconds after the occurrence of power imbalance. After 30 seconds, when the total primary reserve must be fully activated, the system frequency is stabilised at a stationary value, but without restoring its set-point value.

Secondary control is used to restore frequency at the set-point value and to eliminate the deviation of real power exchanges from scheduled ones between control areas/blocks. Also, secondary control frees up the primary reserve to restore it, activating secondary reserve in the time-frame of seconds to typically 15 minutes. However, secondary reserve must be activated only in this control area/block where imbalance between generation and demand occurred.

Tertiary control uses tertiary reserve to free up and restore secondary reserve, therefore tertiary reserve must be activated during 15 minutes after disturbance occurrence in a power system. Tertiary reserve must be able to offset the shortfall in generation if secondary reserve is not sufficient to cover the loss of the largest generating unit.

Time control limits discrepancy between synchronous time and UTC (universal time coordinated) that is caused by deviation of actual system frequency in synchronous area from the nominal frequency of 50 Hz.

III. Power and Frequency Control in IPS/UPS Synchronous Area

The approach to power and frequency control used within IPS/UPS synchronous area is a centralized control. The Unified Power System of Russia with dispatching centre in Moscow is responsible for frequency maintenance within whole IPS/UPS. At the same time, other control areas and blocks of IPS/UPS implement the frequency-biased tie-line power control. Basically, the frequency-biased tie-line power control is implemented manually by dispatchers. However, this control is implemented automatically in the Ukraine and Moldova control block and in Siberia control area. Also, the automatic power flow limitations (PFL) on indicated cross sections are performed in IPS of the Urals, IPS of Siberia, IPS of North Caucasus and in IPS of Centre.

A. Primary Control

Usually, there are distinguished two types of primary control in IPS/UPS synchronous area: general primary control and normative primary control. General primary control is performed by all the power stations in a range of possibilities of their primary control systems. The purpose of this control is to maintain the electricity supply to consumers and normal operation of power stations in case of substantial frequency deviations. Normative primary control is performed by certain power stations where the amount of primary reserve is defined in advance. Also, this reserve must always be available for use. Normative control guarantees the quality of primary control and stabilizes overall network power frequency characteristic.

The nominal frequency value in IPS/UPS synchronous area is 50 Hz. The difference between this value and the value of actual system frequency is a frequency deviation. During normal stationary operating conditions this deviation

should be no larger than $\pm$50 mHz. However, the average deviation at any 0.5 hour of the day (24 h) must not exceed $\pm$10 mHz. This requirement is used to maintain actual system frequency in a range of a static security margin of $\pm$20 mHz to avoid frequent calling up of normative primary control during normal stationary operating conditions. If the frequency deviation is larger than security margin the share of primary control reserve which is proportional to this deviation must be activated during a few seconds starting from the incident. Moreover, 50% of the total primary control reserve must be activated during 15 seconds and the rest of 50% of the reserve must be activated by up to 30 seconds after occurrence of the deviation. However, general primary control is activated if the frequency deviation exceeds its dead band of $\pm$75 mHz.

After sudden loss of generation capacity, loss of load or interruption of power interchanges the dynamic frequency deviation must not exceed $\pm$800 mHz and the quasi-steady-state frequency deviation must not exceed $\pm$200 mHz. Frequency deviation of $\pm$200 mHz is a permissable deviation level, but if the deviation exceeds this level, the entire primary control reserve must be fully activated. The frequency must be maintained in a range of $\pm$200 mHz at least during 95% of 24 hours, at the same time the frequency deviation must not exceed the maximum permissable deviation level of $\pm$400 mHz.

B. Secondary Control

As already mentioned above, the secondary control in IPS/UPS is centralized. The central secondary controller located in Moscow controls the frequency. The other secondary controllers control frequency-biased tie-line power and limit power flow on indicated cross sections.

The main regulated parameter used for seconadry control of power interchanges in IPS/UPS synchronous area is area control crror G (ACE) that needs to be controlled to zero on a continuous basis. The ACE is calculated as the sum of power control error and the frequency control error [4]:

$$G = \Delta P + K * \Delta f. \tag{1}$$

Where ΔP is the deviation of actual power interchanges from scheduled ones, Δf is the deviation of system frequency from the set-point frequency, K is a parameter applied to the secondary controller and $K * \Delta f$ is the frequency control error.

If ACE is not equale to zero it means that there is power imbalance in the control area/control block that leads to frequency deviation and power interchange deviation. To restore the system frequency to its set-point value and the power interchanges with neighbour control areas to their programmed scheduled values a secondary control reserve is used. The power imbalance in the control area/control block must be eliminated within 15 minutes.

To keep the ACE to zero, secondary control system must meet certain requirements. A secondary controller that performes secondary control in the corresponding control centre needs to be operated in an on-line and closed-loop manner. In the systems of automatic control of frequency and power flows there need to be used secondary controllers of proportional-integral (PI) type. The proportional factor of the PI type secondary controller may be set in a range 0 – 0.5. Also, the integration time constant may be from 50 seconds to 200 seconds for frequency and power exchange controller and from 30 seconds to 40 seconds for power limitation controller.

The cycle time for the automatic secondary controller must be no larger than 1 second to avoid time delay between occurance of disturbance and controller reaction and response to the disturbance. The transmission of measurements to secondary controller must be performed cyclically with a delay no larger than 1 second. At the same time, the accuracy of frequency measurement for secondary control must be better than $\pm$1 mHz. The accuracy of the active power measurements on each tie-line must be better than 1.0 – 2.0% of its rated value.

C. Tertiary Control

During tertiary control tertiary reserve is used that maintains and restores the necessary amount of secondary reserve. Tertiary reserve must be available at all times to provide reliable operation of secondary control and to cover the loss of the generating unit, if secondary control reserve is not sufficient for its covering. Tertiary reserve may be activated manually or automatically and its activation must begin before complete use of secondary control.

D. Time Control

Time control is performed by dispatching centre located in Moscow. Time control is used to monitor a discrepancy between synchronous time and universal coordinated time (UCT). The normally permissible range of discrepancy is ±20 seconds and the maximum permissible range of discrepancy is ±30 seconds. If at 8 a.m. every day the discrepancy does not exceed normally permissible range, the time correction is not performed. If the time error exceeds normally permissible range, the controller of synchronous time – dispatching centre in Moscow – by 10 a.m. sends commands to all dispatching centres of IPS/UPS to set the time correction offset of ±10 mHz for the next day (24 h). The time correction offset that is more than ±10 mHz is not permissible according to operational conditions of normative primary control [4].

IV. Power and Frequency Control in ENTSO-E RG CE Synchronous Area

The approach to power and frequency control used within ENTSO-E RG CE synchronous area is a decentralized control. Each control area is responsible for primary control within its territory. Also, it should maintain scheduled values of power interchanges with adjacent control areas. Control areas which work together in the secondary control function with respect to the rest of synchronous area constitute control block.

A. Primary Control

Primary control in Continental Europe synchronous area is based on principle of joint action. It means that all generators in each control area/block must react and respond to deviation in the system frequency. The contribution of each control area/block to the correction of frequency deviation is determined by its respective contribution coefficient to primary control. This contribution coefficient reflects the share of control area/block generation in total electricity generation in the synchronous area. In order to ensure that each control area/block makes its contribution to primary control, the network power frequency characteristic of each control area/block should remain as constant as possible.

The nominal frequency value in ENTSO-E RG CE is 50 Hz. In order to keep the value of actual frequency to this set-point value as closely as possible, the insensitivity of controllers that activate the primary reserve in response to imbalance between generation and demand should be as small as possible, and not larger than ±10 mHz. Therefore to avoid activation of primary reserve in undisturbed operation or at near nominal frequency, the deviation of system frequency should not exceed ±20 mHz. However, possible stationary frequency deviation in normal operational conditions may be ±50 mHz.

In case of instantaneous deviation between generation and demand (by the sudden loss of generation capacity, loss of load or interruption of power interchanges), the maximum permissible dynamic frequency deviation from the nominal frequency must be ±800 mHz. As a reference incident 3000 MW was defined for the entire synchronous area, therefore the primary reserve must be able to cover the shortfall of 3000 MW generation, without the need for customer load-shedding, and primary control must keep the dynamic frequency in a range of 50±0.8 Hz. After 30 seconds from instantaneous deviation occurrence when primary reserve is fully activated a quasi-steady-state frequency must be in a range of 50±0.2 Hz. At the same time, if the quasi-steady-state frequency deviation is of ±200 mHz or more the entire primary reserve must be fully activated. The deployment time of the primary reserve should be as small as possible and in any case 50% or less of the total primary reserve must be activated within 15 seconds and the deployment time for the rest 50% of the total primary reserve must rise linearly to 30 seconds.

B. Secondary Control

The organisation of a secondary control within control blocks in ENTSO-E RG CE systems varies and depends on a structure of the control block. If control area's boundaries coincide with control block's ones, centralised secondary control is applied in this control area/block. If a control block consists of two or more control areas, the organisational structure of secondary control within this block may be centralised, pluralistic or hierarchical. The leading TSO, who is the block coordinator, should be able to maintain the total power interchange of the block towards all other control blocks at the scheduled value.

In contrast with primary control, during which all generation sets of synchronous area provide mutual support by the supply of primary reserve, secondary control should react to a power unbalance and activate secondary reserve only within this control area/block, in which the imbalance between generation and demand has occurred. During seconary control the frequency of affected control area/block must be restored to its set-point value of 50 Hz and the power interchanges with adjacent control areas to their programmed values. At the same time, secondary control may not counteract the action of the primary control. 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 [5]:

$$G = P_{meas} - P_{prog} + K_{ri}(f_{meas} - f_0). \qquad (2)$$

Where $P_{meas} - P_{prog}$ is the deviation of actual power interchanges P_{meas} from scheduled ones P_{prog}, K_{ri} is a constant applied to the secondary controller and $f_{meas} - f_0$ is the deviation of instantaneous system frequency f_{meas} from the set-point frequency f_0.

The ACE must be kept to zero as close as possible. The reasons for this requirement are to maintain the balance of control area/block and not to impair the primary control action. And not to impair the primary control action under conditions of uncertainty on the self regulating effect of the load, K_{ri} for a given control area may be chosen slightly higher than the rated value of its network power frequency characteristic.

In order to control the ACE to zero, secondary control must be performed in the corresponding control centre by a single automatic secondary controller that needs to be operated in an on-line and closed-loop manner [6]. To minimise the time delay between occurrence of incident and controller response to it, the cycle time for the automatic secondary controller should be between 1 second and 5 seconds. Thereby, the delay of transmission of measurements to the secondary controller must not exceed 5 seconds and it must be below the controller cycle time. Since the values of actual system frequency and active power during secondary control are monitored, the requirements to accuracy of their measurements have been set. The accuracy of measurements of active power on each tie-line must be better than 1.5% of its rated value, and the accuracy of frequency measurements must be between 1.0 mHz and 1.5 mHz.

If the control deviation occurs, the secondary reserve must be activated to return the ACE to zero. During the usage of secondary reserve that begins within 30 seconds from disturbance occurrence frequency and power interchanges return to their set point values, and this process of correction must be completed within 15 minutes. To be able to fulfil these requirements, the following minimum value for secondary reserve R is recommended in control area concerned with the maximum anticipated load L_{max} [6]:

$$R = \sqrt{aL_{\max} + b^2} - b. \qquad (3)$$

Where R is the recommendation for secondary control reserve, L_{max} is the maximum anticipated load in MW for the control area/block, a and b are parameters established empirically: a = 10 MW and b = 150 MW.

According to the equation (3), for instance, secondary control reserve of 300 MW is recommended for a control area with maximum anticipated load of 20000 MW.

C. *Tertiary Control*

Tertiary control provides tertiary reserve (sometimes referred as 15 minute reserve) which is activated after activation of secondary control to free up and restore the secondary reserve. Also, tertiary reserve is required to offset the shortfall of secondary reserve, if the amount of secondary reserve is not sufficient to cover the loss of the largest generating unit. In addition, activation of tertiary reserve should distribute the secondary reserve to the various generators according to economic criteria.

D. *Time Control*

The discrepancy between synchronous time and UTC time that does not need for time correction should be within a range of ±20 seconds. Under normal conditions in case of trouble-free operation of the interconnected network the discrepancy should be within a range of ±30 seconds. The discrepancy in a range of ±60 seconds is tolerated only under exceptional conditions. The calculation of synchronous time is performed at 8 a.m. every day by the Laufenburg control centre located in Switzerland. This centre is also responsible for time correction. If discrepancy between synchronous time and UTC time exceeds a range of ±20 seconds, the information for time correction is sent to each control area/block by 10 a.m. In case of correction procedure it is set the time correction offset of ±10 mHz for secondary control in each area during the next day (24h). The offsets larger than ±10 mHz may be used only under exceptional conditions.

V. Similarities and Differences Between IPS/UPS and ENTSO-E RG CE Power and Frequency Control Principles

The Standard on Frequency and Active Power Control in UPS and Isolated Systems of Russia has been recently harmonized on the basic conceptions with ENTSO-E Operation Handbook. However, the differences between these regulating documents still exist. The main similarities and differences between the Standard and Operation Handbook that were defined in the course of analysis of these documents are considered below.

A. *Similarities*

The main criteria used to distinguish the size of frequency deviation for primary control are the same in the both systems: the primary reserve is activated if the frequency deviation exceeds ±20 mHz, the possible stationary frequency deviation in normal operational conditions may be no larger than ±50 mHz, the maximum quasi-steady-state frequency deviation must be in a range of ±200 mHz and the maximum instantaneous frequency must not exceed 800 mHz.

The requirements for the deployment times of reserves are the same in IPS/UPS and ENTSO-E RG CE systems: primary reserve must be activated during a few seconds starting from the incident. The deployment time for 50% of the total primary reserve is 15 seconds and the rest 50% of the reserve must be fully activated within 30 seconds. After full activation of the primary reserve the secondary reserve must be activated to free up the primary control. The secondary reserve must restore the set-point frequency and scheduled power exchanges during 15 minutes. If secondary reserve is insufficient, tertiary reserve must be activated during 15 minutes after occurrence of instantaneous imbalance to free up the secondary control and cover the shortfall in generating capacity.

The approach to time control is very similar in both synchronous areas: calculation of synchronous time and its correction is performed by a single dispatching centre within the synchronous area. The time correction must be performed if the discrepancy between synchronous time and UTC time exceeds ±20 seconds and all dispatching centres must set the time correction offset of $\pm$10 mHz for the next day (24 h). However, the discrepancy in a range of $\pm$60 seconds and the offsets larger than $\pm$10 mHz are tolerated under exceptional conditions in Continental Europe synchronous area that is not permissible in IPS/UPS system.

B. *Differences*

The most important difference is in the approach to organization of frequency control. As mentioned above, IPS/UPS uses centralized philosophy of frequency control according to which the Unified Power System of Russia with dispatching centre in Moscow is responsible for frequency maintenance within whole IPS/UPS system. At the same time, ENTSO-E RG CE uses decentralized approach where each control area/block is responsible for frequency control. This difference is caused by different structure of these synchronous areas.

The different approach to organization of frequency control leads to different principles that are used for secondary control. So, the secondary control in IPS/UPS synchronous area means the control of tie-line power flows and only IPS Centre is responsible for frequency control. In ENTSO-E RG CE system secondary control always means control of ACE on control block borders.

The structure of organization of primary reserve in IPS/UPS also has its peculiarity in comparison with the structure used in ENTSO-E RG CE. There are two types of primary control in IPS/UPS system: general primary control and normative primary control. General primary control is performed by all the power stations in a range of possibilities of their primary control systems. This control applied if the frequency deviation exceeds $\pm$75 mHz. Normative primary control is performed by certain power stations and it activates normative reserve if the deviation of system frequency exceeds $\pm$20 mHz. In contrast to this, all generating units of ENTSO-E RG CE system have the same requirements for providing the primary reserve and all of them must take part in this process if the frequency deviation exceeds $\pm$20 mHz.

Additionally, the requirements for the accuracy of frequency measurements and transmission of these measurements to secondary controller are stricter in IPS/UPS than in ENTSO-E RG CE. For instance, transmission of measurements to secondary controller in IPS/UPS must be performed with delay no larger than 1 second. At the same time, in ENTSO-E RG CE this delay may be between 1 second and 5 seconds.

VI. Conclusion

ENTSO-E RG CE is a huge system which is twice larger than IPS/UPS by installed generating capacity and consumption. This system connects most Western European countries. IPS/UPS is a large system geographically, but it was built to operate together, therefore it uses centralized control model. So, it will be a big challenge to interconnect synchronously the large centralized IPS/UPS system with a decentralized system like ENTSO-E RG CE.

Synchronous interconnection of IPS/UPS with ENTSO-E RG CE will create a new huge synchronous area where decentralized control structure will probably be used. Therefore, the ENTSO-E RG CE experience in connection of a large number of countries will be very useful in case of creation of this single synchronous area. However, it is important to take into account that currently there is relatively weak interconnection between IPS/UPS and ENTSO-E RG CE, therefore creation of a single synchronous area will require large investments to strengthen this interconnection.

Also, the big question is, if IPS/UPS would like to connect with ENTSO-E RG CE from frequency control point of view? As a huge number of wind parks located in ENTSO-E RG CE influences the system frequency significantly. For instance, currently there are 81 GW of installed net capacity of wind parks from 916 GW of total installed net generating capacity. Such a huge amount of installed capacity of wind parks makes frequency control challenging.

Nevertheless, frequency control models that used in IPS/UPS and ENTSO-E RG CE are compatible and they do not exclude the synchronous interconnection between these two systems.

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