OPTIMAL DETERMINATION AND ALLOCATION OF SECONDARY FREQUENCY CONTROL RESERVE IN A MARKET ENVIRONMENT CONSIDERING ACE CRITERIA

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I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

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ABSTRACT

OPTIMAL DETERMINATION AND ALLOCATION OF SECONDARY FREQUENCY CONTROL RESERVE IN A MARKET ENVIRONMENT CONSIDERING ACE CRITERIA

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Frequency control in Turkey is realized under four main tasks, namely; primary, secondary, tertiary frequency control and time control according to European Network of Transmission Operators for Electricity (ENTSO-E) regulations. As being a part of an interconnected electricity network, secondary frequency control mechanism, which is realized by the utilization of an Automatic Generation Control (AGC) System, plays a crucial role in the achievement of two important goals. One of them is maintaining the frequency at the nominal value while the other one is keeping the active power flow through interconnection lines at scheduled values. Challenge of achieving these two goals originates from the existence of rapidly changing loads which create significant deviations in the frequency of the network and undesired power flows on tie lines.

In this thesis study, an iterative algorithm to determine the amount of reserve with minimum cost while satisfying the ENTOE-E criteria regarding Area Control Error (ACE) is developed. Cost minimization of the reserve support is conducted based on the price bids of the power plants participating in AGC system in the day-ahead electricity market. Satisfaction of ACE criteria is validated by dynamic simulations of a simplified ENTSO-E dynamic model including governor settings of the machines.

As a result of these studies, amount of reserve to be held on an hourly basis is determined in a systematical way. Furthermore, allocation of fast and slow responsive reserve groups is determined for the use of system operators in National Dispatch Center.

Keywords: Secondary Frequency Control, Automatic Generation Control

ÖZ

ELEKTRİK PİYASASI KOŞULLARINDA SEKONDER FREKANS KONTROLÜ REZERV MİKTARI VE DAĞILIMININ ALAN KONTROL HATASI KRİTERLERİ DİKKATE ALINARAK BELİRLENMESİ

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Türkiye'de frekans kontrolü primer, sekonder, tersiyer frekans kontrolü ve zaman kontrolü olmak üzere Avrupa Elektrik İletim Sistemi Operatörleri Birliği'nin (ENTSO-E) belirlemiş olduğu kurallar doğrultusunda dört seviyede gerçekleştirilmektedir. Türkiye'nin enterkonnekte bir sistemin üyesi olması dolayısıyla Otomatik Üretim Sistemi (AGC) aracılığı ile gerçekleştirilen sekonder frekans kontrol hizmeti çok önemli iki temel görevi yerine getirmektedir. Bunlardan ilki sistem frekansının nominal değerinde tutulması, diğeri ise Avrupa ile olan bağlantı hatlarındaki aktif güç akışlarının planlanan seviyelerde olmasını sağlamaktadır. Bu görevlerin yerine getirilmesindeki en büyük zorluk ise sistem içerisindeki ani değişen yüklerin sistem frekansında sapmalara ve bağlantı hatlarında istenmeyen aktif güç akışlarına sebebiyet veriyor olmasıdır.

Bu tez çalışmasında, ENTSO-E'nin belirlemiş olduğu alan kontrol hatası kıstasları göz önüne alınarak saatlik bazda sekonder frekans kontrolü rezerv miktarının belirlenmesi ve bu miktarın en ucuz şekilde sağlanması amacıyla iterasyona dayalı bir algoritma geliştirilmiştir. En ucuz maliyetin belirlenmesi hususunda piyasa oyuncularının gün öncesi elektrik piyasasındaki fiyat teklifleri esas alınmıştır. Alan kontrol hatası kriterlerinin sağlanmış olup olmadığı ise basitleştirilmiş Avrupa elektrik ağı modelinin dinamik olarak simüle edilmesi neticesinde kontrol edilmektedir.

Geliştirilen yöntem ile Milli Yük Tevzi Merkezi'ndeki sistem operatörleri için saatlik bazda gerekli sekonder rezerv miktarı sistematik bir yaklaşımla belirlenmektedir. Ayrıca, bu rezervin hızlı ve yavaş tepki veren santral grupları içerisindeki dağılımı da bulunmaktadır.

Anahtar Kelimeler: Sekonder Frekans Kontrolü, Otomatik Üretim Kontrolü

To My Parents

And My Brother

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TABLE OF CONTENTS

LIST OF TABLES

TABLES

LIST OF FIGURES

FIGURES

CHAPTER 1

INTRODUCTION

An electrical power system consists of equipment which is responsible for generation, transmission and distribution of the electrical energy. First power system around the world was built as a DC network in 1880s in New York City. However advantages of AC systems over DC systems such as transferring energy from long distances, simplicity of AC generators, etc., have led the usage of AC systems more broadly. Today, most of the electrical networks designed and operated according to AC principles with different levels of two main quantities; voltage and frequency.

Quality of service is one of the main objectives of a modern power system. Therefore steadiness of voltage and frequency levels at desired values carries great importance in the assessment of quality of an electricity network. As being a dynamic system, power systems are subject to a wide variety of disturbances starting from minor changes in load to loss of considerable amount of generation. Therefore tracking and control of voltage and frequency levels are required for a satisfactory operation of the power system.

After vertical unbundling of the system structure, TEİAŞ took the responsibility of the operating, controlling and maintaining the transmission system. Control of voltage and frequency is utilized under the name of ancillary services. Ancillary services may be grouped in two categories, namely; voltage control and frequency control.

Voltage, as being a local indicator, is highly correlated with the reactive power flow in the power system. Voltage control is achieved in three hierarchic stages, namely; primary voltage control, secondary voltage control and tertiary voltage control. Primary voltage control concerns with the voltage level at the busbar that generator unit is connected. Secondary voltage control is realized by means of changing the tap positions of transformers, switched shunts (capacitors or reactors) or commitment of another unit to support voltage while realizing desired levels. Finally tertiary voltage control determines the voltage setpoints of the high voltage busbars of the power plants.

Frequency control of a power system deals with the maintaining balance between generated and consumed power. Therefore, electrical power has to be consumed at the time it is generated. However, load in system changes continually during the day. In addition to that, power systems may be subjected to unexpected disturbances which create an unbalance between generation and consumption in the system.

Frequency control of an interconnected system is realized in four main groups, namely; primary, secondary, tertiary frequency control and time control. Primary control mechanism is realized by measuring the difference between rotor speed and reference speed, and responding proportionally to this difference. Reserve capacity for primary frequency control is determined in various ways including some probabilistic approaches. After establishment of a synchronous connection with the European electricity network, maintained reserve capacity for primary control of frequency is decreased. Since any disturbance in a specific point of supported by the all generators in the synchronized system, decreasing the amount of primary reserve capacity does not bring any negative effects from stability and security point of views.

However, response of all generators in the system upon a disturbance in a specific control area brings the need of secondary frequency control action in order to maintain the power flow on tie lines at scheduled values and bring the frequency back to its nominal value. Secondary control is performed by utilization of Automatic Generation Control (AGC) systems. In order to change the generators power output setpoints upon a mismatch between scheduled and measured exchange power are sent to AGC participants.

In this thesis study, an iterative algorithm to determine the amount of secondary frequency control reserve with minimum cost while satisfying the ENTSO-E criteria regarding Area Control Error (ACE) is developed. Cost minimization of the reserve support is conducted based on the price bids of the power plants participating in AGC system in the day-ahead electricity market. In order to achieve this, mixed integer linear programming (MILPROG) tool of MATLAB is utilized. Satisfaction of ACE criteria is validated by dynamic simulations of a simplified ENTSO-E dynamic model including governor settings of the machines by using DigSilent power system analysis software.

In Chapter 2, general background on power system stability and control is provided. Basics of voltage and frequency control are explained. Furthermore, more specifically on frequency control, frequency control mechanism in Turkey and fundamentals of secondary frequency control depicted in detail. Working principle and the logic behind the AGC system is discussed. In addition to the above mentioned topics, effects of electricity market on determination and allocation of secondary frequency control reserve is explained. At the end of Chapter 2, proposed approach regarding secondary reserve is discussed from technical and economical point of views.

Chapter 3 starts with the explanation of the AGC system in Turkish electricity network. Following this explanation, ACE performance criteria regarding Turkish AGC system from ENTSO-E point of view is given. Then, the dynamic system model that is used in simulations is explained. Moreover, assumptions and simplifications during dynamic modelling are discussed. Additionally, selection procedure of the power plants regarding the provision of reserve support is explained with illustrative examples. Problem formulation in order to minimize the cost of reserve support is given in detail. Finally in Chapter 3, overall procedure regarding the determination and allocation of secondary reserve is presented.

In the fourth chapter of the thesis, preparation of the test data to be used in simulations in dynamic analysis to represent the variation of demand is explained. Three different scenarios are investigated through simulations with different levels of total demand. Test data are formed by combination of EAF measurements which are obtained from National Power Quality Monitoring project. In each scenario, an iterative approach is utilized as explained in Chapter 3 and amount of secondary reserve and corresponding allocation among AGC participants are determined with minimum cost.

In the concluding chapter, results of simulated scenarios are discussed. Moreover economic benefits of the proposed algorithm for determination and allocation of the secondary reserve are explained. Moreover future studies regarding the utilization of the algorithm for system operators in National Load Dispatch Center are mentioned.

CHAPTER 2

GENERAL BACKGROUND ON POWER SYSTEM STABILITY AND CONTROL

2.1. Power System Stability

An electrical power system is a network with group of equipment responsible to generate, transmit and distribute energy where it is used. An electrical system is said to be stable depending on its ability to reach an equilibrium point after being subjected to a disturbance [1].

Frequency and voltage are the two main key points when evaluating the power system stability. Frequency is an indicator of the balance between generation and consumption in the system. When amount of power that is generated is greater than consumption; system frequency increases due to storage of the excessive energy in rotating masses. This may lead tripping of some generators in the system, i.e., going out of service.

On the other hand, when the amount of consumption is greater than generated power, system frequency decreases. It is due to the fact that mismatch power is supplied by the stored mechanical energy in rotating masses.

All equipment in electrical system show either capacitive or inductive characteristics besides resistive behavior. Therefore; reactive power flow in an electrical system is as important as active power flow. Since reactive power flow is highly dependent to type of the equipment and load demand, voltage comes as a local indicator showing status of a restricted area.

Electrical power systems show nonlinear characteristic which is the case for most of the dynamic systems. This phenomenon brings the requirement for system modelling in order to analyze the network. While making dynamic analysis the term, system state, is the keyword which carries the information regarding the current status of the operating conditions.

Power systems are subjected to disturbances continually. These disturbances are in a wide range including change in load, loss of generation, transmission line faults, etc. For the system to operate satisfactorily after being subjected to a disturbance, initial state of the system carries as much importance as the nature of disturbance. Same disturbance applied to the same system may result differently depending upon the initial state of the system.

There are many equilibrium states in a power system as being a nonlinear dynamic system. Disturbances make the system change from one state to another one. But the new state is not necessarily to be a stable one. Following a disturbance, power system may be stable or unstable depending on the nature of disturbance. It is not feasible to design a power system that can handle all kinds of disruptive disturbances. Power systems are designed to be stable up to some level of disturbances, i.e., loss of the biggest unit or a circuit breaker opening of the highest capacity transmission line. Moreover probability of occurrence of such big disturbances is also being taken into consideration during planning phase of the grid.

System response to any kind of disturbance is a joint action of grid elements. For example, a fault on a transmission line may lead the circuit breakers open, which may lead to tripping of a generator. Loss of a generator leads to an imbalance between generation and consumption which causes a decrease in frequency. Then, due to decrease in frequency, governors of the units in the system will act to recover the frequency. Moreover, voltage level of the system may differ due to loss of reactive support of the tripping unit, which may result changes in voltage or frequency dependent loads. Because of voltage deviations, voltage regulators will also act. These responses may lead the system to reach a stable point or sometimes not sufficient to reach a stable point depending on how disruptive the disturbance is. In a pessimistic scenario, a blackout of the system may also occur after cascading events.

Power systems are experiencing disturbances continually. But, in the evaluation of system stability upon a disturbance, it is convenient to assume that the system is at a steady state condition initially.

2.1.1. Classification of Power System Stability

Power system stability problem, as being a complex problem, deals with great number of elements and their responses. The response characteristics of the elements vary in a wide range of time starting from microseconds to minutes. Depending on the physical nature of the elements, power system dynamics can be grouped under 4 main sections, namely, wave phenomena, electromagnetic phenomena, electromechanical phenomena and thermodynamic phenomena. In Figure 2.1 below, time frame of the power system dynamic phenomena is presented.

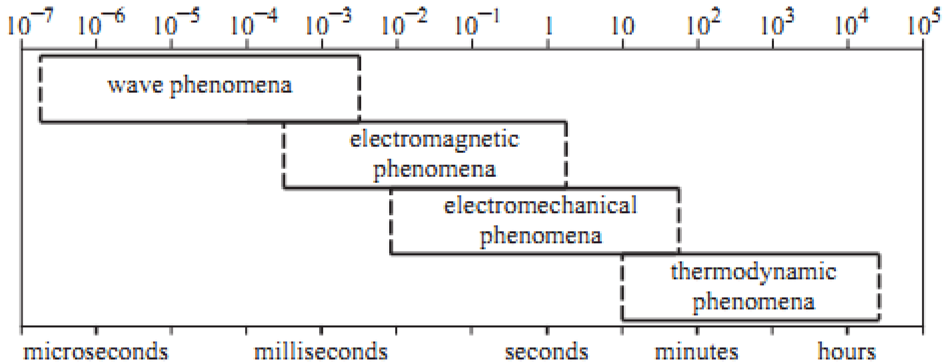


Figure 2.1 Time Frame of the Basic Power System Dynamic Phenomena [2]

In the first group, time frame is in the order of microseconds. Surges, lightning strikes and switching actions belong to this group. For example, during opening action of a circuit breaker, transient recovery voltage is observed across the terminals of a circuit breaker and this voltage may reach up to 2 per unit. This increase in voltage is explained with wave phenomena, specifically travelling of wave through the transmission line and its reflection which are recognized in the order of microseconds. The second group, electromagnetic phenomena deal mainly with electromagnetic interactions within the generator armature and damper windings upon a disturbance occurred in the network without any considerable change in rotor speed since time constant of this group is in the order of milliseconds. The third group, electromechanical phenomena, involves oscillations of rotors, power swings in network etc. including the variations in rotor speed after a disturbance, or isolation of equipment after a fault occurrence in the system. And finally the last group, thermodynamic phenomena, focuses on the thermodynamic nature of the steam turbines due to boiler control. Main focus of this thesis, the automatic generation control system regarding the secondary frequency control, is categorized under the electromechanical phenomenon.

Taking into consideration of the wide range of the time span and complexity of the power system dynamic analysis, it is wise to classify the stability problem at interest and creating a system model accordingly. While creating the system model, in order to make simplifications, assumptions are made up to some degrees to reduce the size of the model regarding the type of problem. One assumption can be acceptable for a specific type of analysis and unacceptable for another. Key factors of interest in the evaluation of the stability problem that is being under consideration may vary based on the nature of the problem. Moreover, analytical techniques to be used may vary depending on the type of the stability problem. Therefore, classification of power system stability is essential for discrimination of assumptions, determination of the resolution of the created model and selection of the analytical methods.

Classification of power system stability presented below in Figure 2.2 depends on the following considerations:

- The main system indicator, i.e., voltage or frequency, that is affected upon a disturbance,
- The severity of the disturbance,
- Assessment of stability from time span point of view.

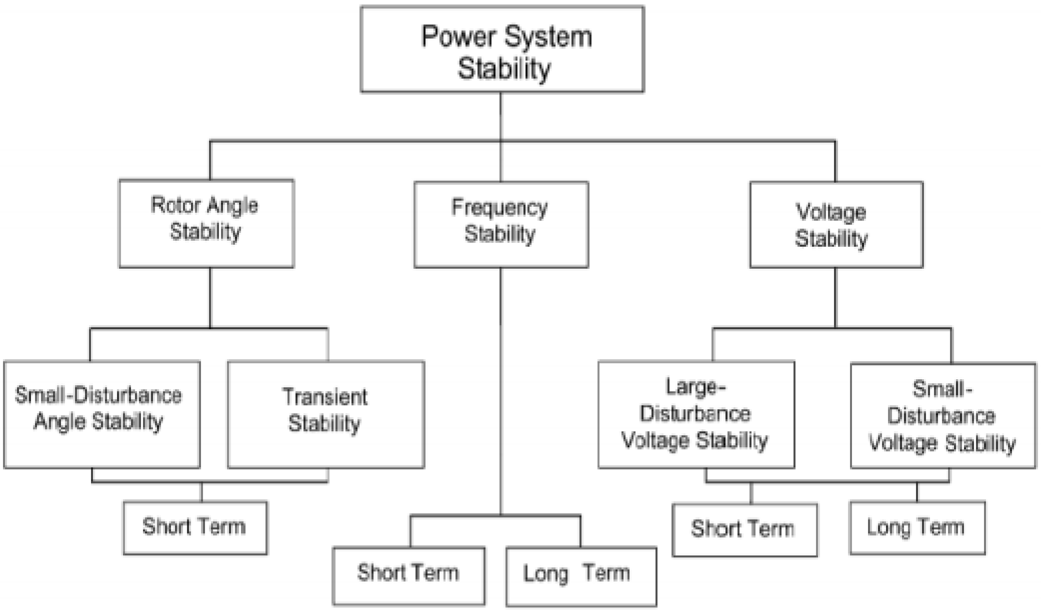


Figure 2.2 Classification of Power System Stability [2]

As mentioned previously, as being a nonlinear system, initial state of the system and the size of the disturbance are the main concerns of power stability problem. Stability of non-linear systems can be locally evaluated using eigenvalues by linearizing the system around the point of interest for small disturbances. As a result of this, voltage and rotor angle stability can be classified into two groups in terms of disturbances, namely small and large (transient for rotor angle stability) disturbances.

On the other hand, frequency control can be achieved via automated systems such as automatic generation control (AGC) or manually by the system operator in the national dispatch center. These actions have different time spans. Therefore frequency stability problem is classified in two groups; namely, short term and long term stability.

When a power system is subjected to a disturbance, active and reactive power flows in the system change. Depending on the type of the disturbance, topology of the system may change, i.e., opening of a transmission line. As a result of change in load flow, voltage levels in the system changes and rotors of the generators start to oscillate within the first few seconds. Any mismatch between the generation and consumption will also change the system frequency. Change in frequency activates the governor actions of generators in the system. Besides events explained above, rotor angles may oscillate because of the response of excitation systems which may also take system to an instable point of operation.

2.2. Power System Control

Electrical power system is a network with a group of equipment responsible to generate, transmit and distribute energy where it is used. Most of the time energy is used in other forms, namely heat, light and mechanical forms rather than electrical form. Using the electrical form of energy is advantageous from the efficiency and reliability point of views. A properly designed and operated power system should satisfy the following fundamental requirements [1]:

- System should satisfactorily meet the active and reactive power demand of load which changes continuously over time. Since there is no convenient and efficient way of storing electrical energy in great amounts, generator power outputs of the system should track the demand of the load in real time.

- Power demand must be supplied at minimum cost after commitment of units without any considerable effect to environment.

- The quality measurement parameters, namely voltage and frequency of the system, must be kept within the acceptable limits defined by grid code.

According to above mentioned fundamental requirements of power system, architecture of power system controllers is shown in Figure 2.3. There are two main stages of controls, namely system generation control and transmission controls. Transmission controls are responsible for maintaining the two important quality parameters, voltage and frequency, in acceptable limits. This is accomplished by individual support of each generating unit in the system. Reactive support of generator unit is realized by excitation system via changing field current. On the other hand active power output of generating unit is adjusted by governing actions.

Transmission controls also include other active and reactive power control elements. Static Var Compensators, HVDC transmissions, phase-shifting transformers, reactors and capacitor banks, etc., are also needed to be controlled in order to meet the normal operating conditions of the power system. However, control objectives for a normally operating system may be different than the case when power system is subjected to a disturbance, i.e., different objectives may be required to be met in order to avoid any undesired consequences such as brownout and blackouts.

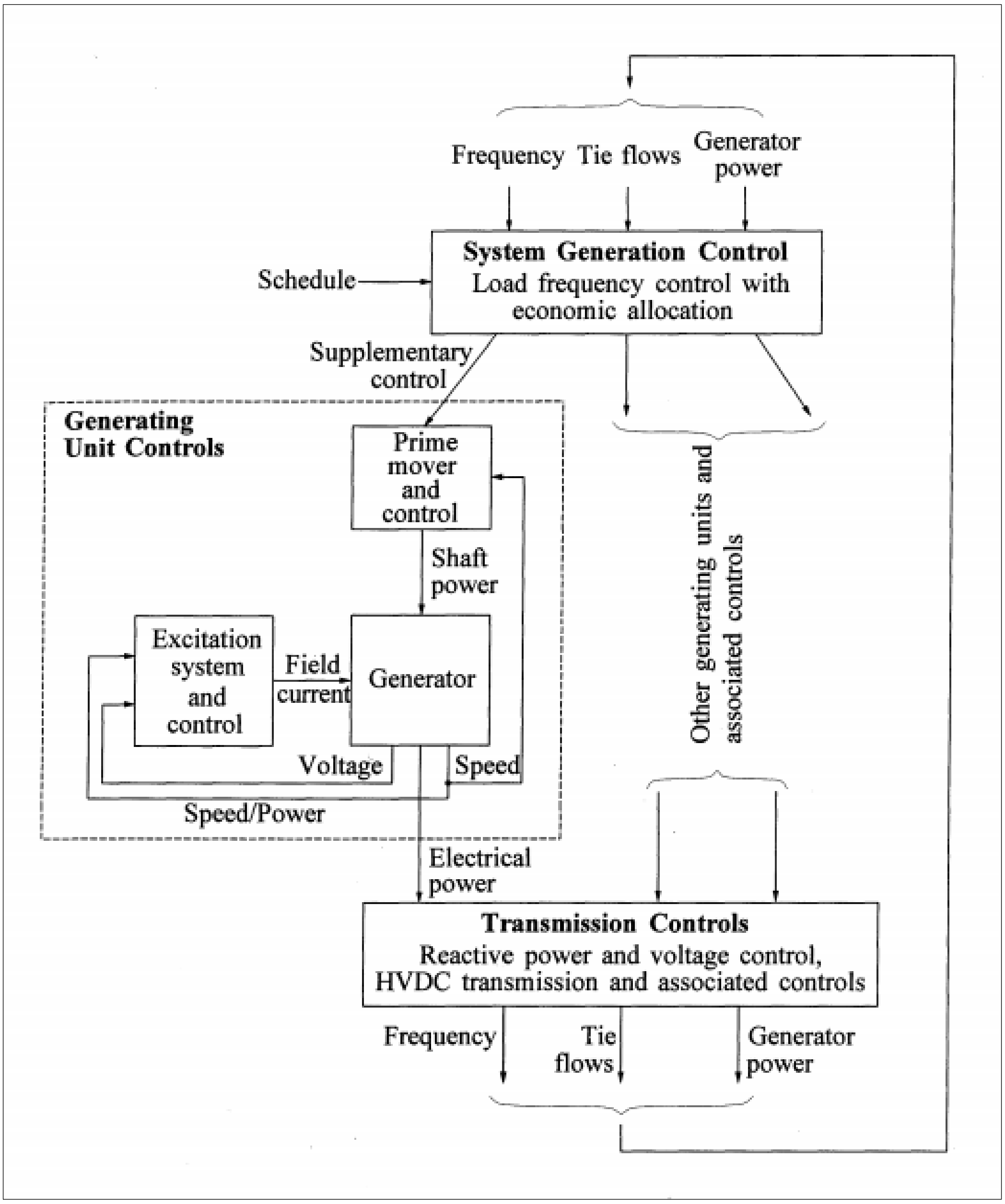


Figure 2.3 Structure of Power System Controllers [1]

2.2.1. Voltage Control

Voltage stability of a power system can be defined as the capability of power system to main voltage levels at the substations within acceptable limits after being subjected to a disturbance. Poor performance of voltage control may result in loosing of some loads in the grid. Moreover, generator tripping and circuit breaker opening of transmission lines may be realized by means of protective actions.

In a power system, voltage control is achieved in three hierarchic stages as in the case of frequency control, namely; primary voltage control, secondary voltage control and tertiary voltage control. Schematic diagram of voltage control tasks is presented in Figure 2.4.

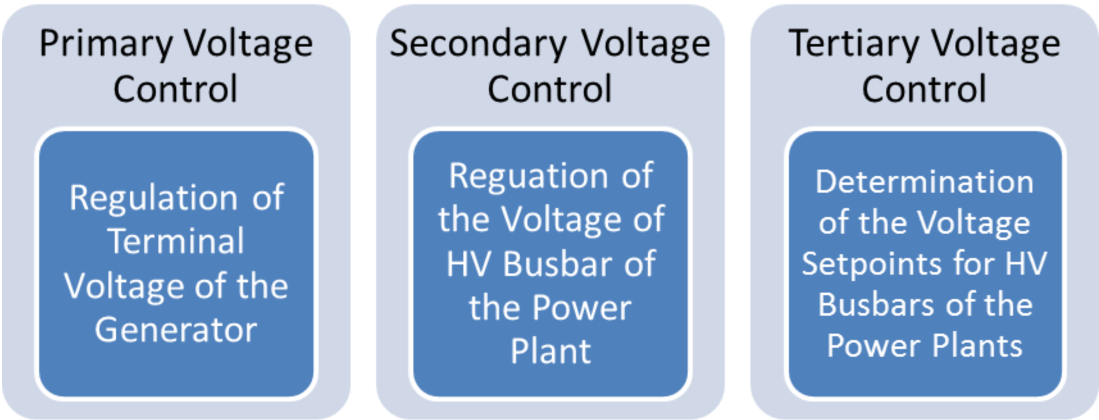


Figure 2.4 Voltage Control

Primary voltage control concerns with the voltage level at the busbar that generator unit is connected. This is achieved by adjusting the field current in the excitation system of the unit within the operating limits. Automatic Voltage Regulators (AVRs) play the key role in controlling the excitation system. Primary voltage control acts very fast in order to prevent any instability problem in the voltage which is one of the two main electrical quantities.

Secondary voltage control is realized by means of changing the tap positions of transformers, switching shunts (capacitors or reactors) or committing another unit to support the voltage while realizing desired levels. Moreover secondary control, by releasing primary control action, helps the AVR system to be capable of reacting to cascading disturbances. Secondary voltage control is relatively slow than primary control due to the mechanical work included in the operation.

Finally tertiary voltage control determines the voltage setpoints of the high voltage busbars of the power plants in order to prevent unnecessary reactive power flow through the system. For example, poor control of adjusting voltage setpoints in the system may result in parallel flows. In such a case, one of the power plants in the region injects reactive power to the grid while neighboring power plant absorbing that reactive power. In order to avoid such flows in the grid, successful operation of tertiary control is required throughout the network.

2.2.2. Frequency Control

Electrical power has to be consumed at the time it is generated. Therefore there should be a balance between generation and consumption in a power system. Any mismatch between generation and consumption results deviation in frequency from its nominal value.

Frequency of an electrical system is a measure of the rotation speed of the generators acting synchronously. Increase in the total load will decrease the frequency of the system whereas decrease in total load increases system frequency assuming a constant level of generation.

In an electrical power system, system load changes continuously during the day. This variation depends on many factors such as whether conditions, hours of labor, length of day time, special holidays, etc. These changes in demand can be forecasted with various tools depending on the historic statistical data. Moreover rate of change of demand as a consequence of the above mentioned reasons are not high to change the state of the system from a stable point to an unstable one.

However, unexpected faults may occur in power systems. Following a fault in the system, balance between generation and consumption will be lost. Since the time constant of an electrical quantity is much smaller than the time constant of a mechanical quantity (generating units in this case), it is natural to have such an imbalance. If a large disturbance occurs in the system such as tripping of a generator by means of a protective action, the balance between generation and consumption will be lost and the deficit power will be compensated by the rotating masses of the system, i.e. kinetic energy of rotors. Hence, frequency of the system will start to decrease. Reestablishment of generation-consumption balance is acquired by governor actions of generator units in operation the system. The amount of deviation in frequency depends on the inertia of the system and the reaction speed of generator controllers in increasing/decreasing units' power outputs.

Frequency control of an interconnected system is realized in four main categories, namely; primary, secondary, tertiary frequency control and time control according to European Network of Transmission System Operators for Electricity (ENTSO-E) Regulations [3]. The balance between generation and consumption is satisfied by the frequency control philosophy presented in Figure 2.5. These categories will be explained in the following sections.

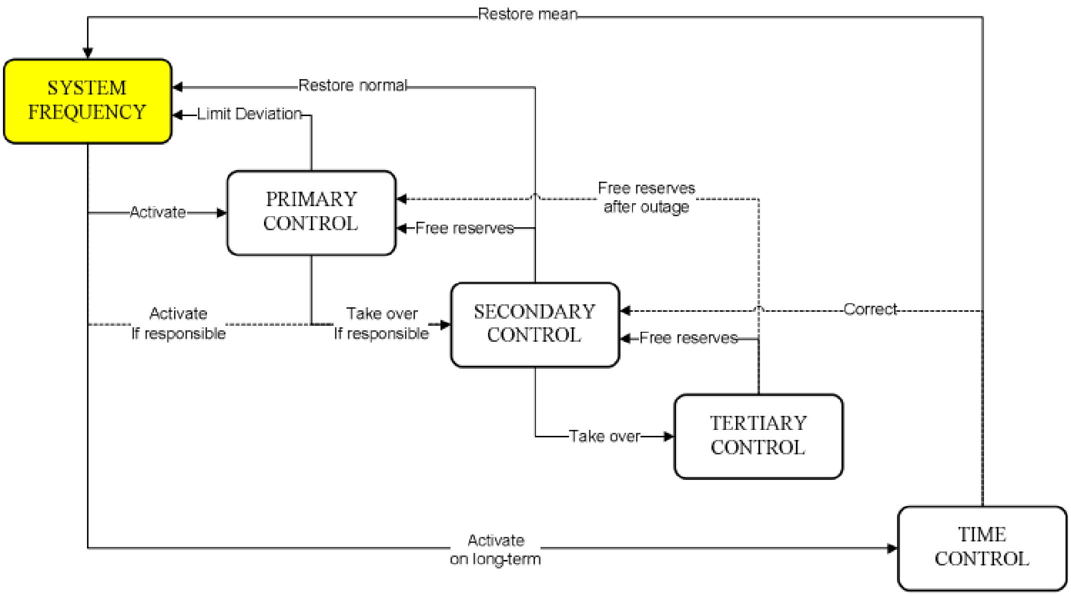


Figure 2.5 Frequency Control Philosophy [3]

2.2.2.1. Primary Frequency Control

System frequency of an electrical power system is highly correlated with the active power. The main purpose of primary frequency control is to create equilibrium between generated and consumed power within a synchronous area by the simultaneous action of the participant TSOs [3]. Any power deficit in a local area has a reflection on the system frequency which is a common parameter for whole synchronous area. Therefore, mismatch between generation and demand is allocated to all generators in the system.

Adjustment of power output of a generator is accomplished by means of a speed governor. Principle regarding the speed governor action is depicted in Figure 2.6.

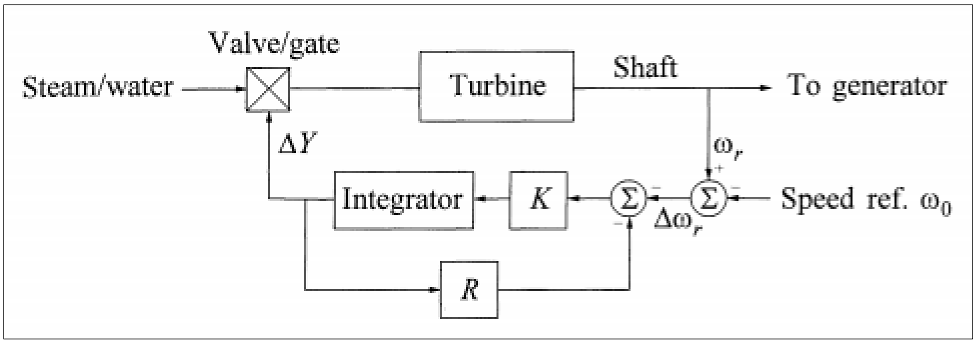


Figure 2.6 Principle of Speed Governor Action [2]

As understood from Figure 2.6, speed governors act in primary control in a way such that, actual rotor speed of generator is compared with the reference speed and a proportional type of response opens/closes the valve/gate of the turbine. If primary source of turbine increases, shaft speed increases. Conversely, if primary source input of the turbine decreases, shaft speed decreases, where ΔY represents the change in valve/gate position and $\Delta\omega r$ being the speed deviation. Finally R is the droop of the generator expressed in percentage in Equation (2-1).

$$R(\%) = \frac{Percentage\ speed\ or\ frequency\ change}{Percentage\ load\ change}\ x\ 100 \qquad (2\text{-}1)$$

This principle of operation is represented graphically in Figure 2.7, where ω_{NL} represents the no-load speed, ω_{FL} holds for speed at full-load and ω_o for the rated speed.

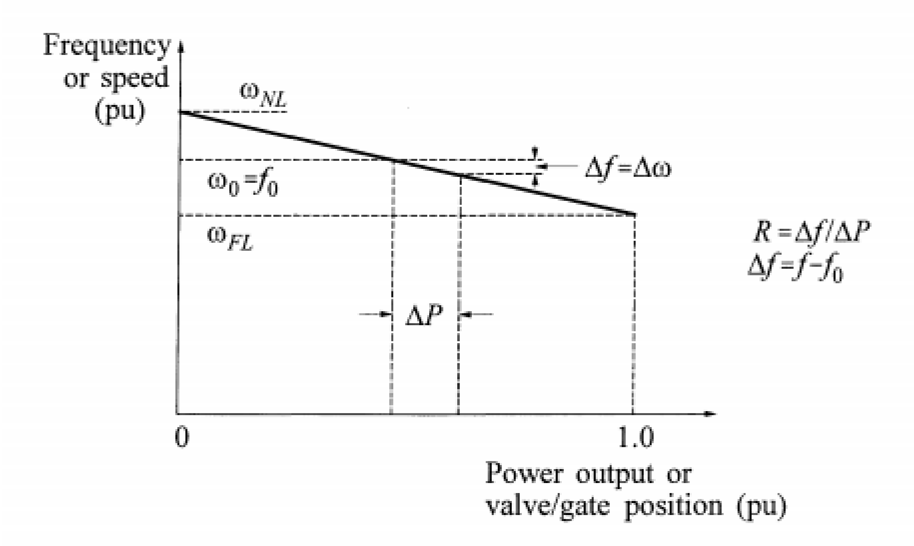


Figure 2.7 Frequency vs. Power Characteristic of a Governor with Droop Feedback

Assume two units having droop characteristic shown in Figure 2.8. P_1 and P_2 correspond to power output of Unit 1 and Unit 2 respectively at nominal frequency. If system load decreases by ΔP_L amount, rotation speed of the units will decrease and governors will increase power output until a new operating f' is reached. Corresponding increases in power outputs are P_1' and P_2' for Unit 1 and Unit 2 respectively.

$$\Delta P_1 = P_1' - P_1 = \frac{\Delta_f}{R_1}$$

$$\Delta P_2 = P_2' - P_2 = \frac{\Delta_f}{R_2}$$

and hence,

$$\frac{\Delta P_1}{\Delta P_2} = \frac{R_2}{R_1} \qquad (2\text{-}2)$$

As mentioned previously, speed governor action changes the generator unit's power output proportional to the system frequency. Therefore it can be said that, primary frequency control maintains the balance between generation and demand by changing the speed of the machines in the system in order to prevent frequency deviations as shown in Figure 2.9.

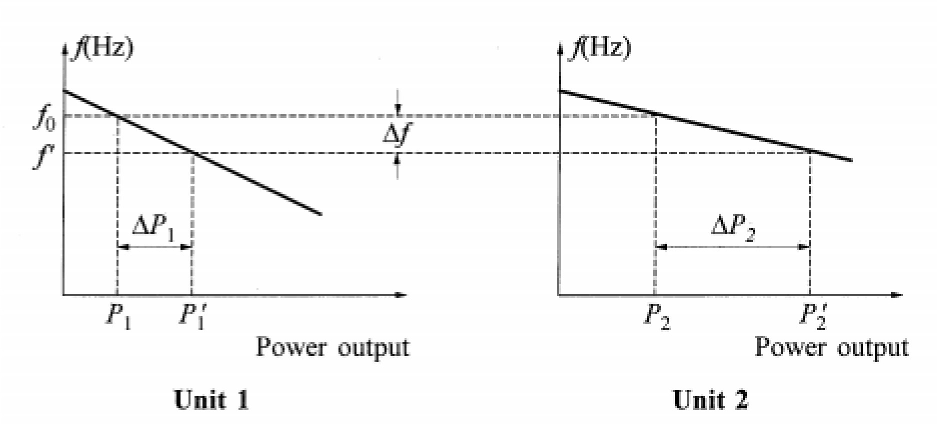


Figure 2.8 Droop Characteristics of Unit 1 and Unit 2

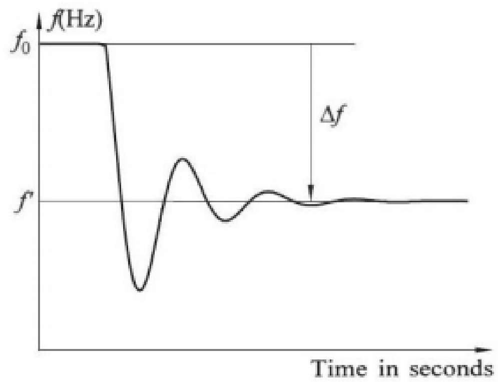


Figure 2.9 Primary Control Effect on System Frequency after a Power Deficit

2.2.2.2. Secondary Frequency Control

As understood from the previous section, the change in demand in a power system creates a deviation in the frequency. Primary control functions as increasing the units' power output to stop the deviation of frequency from its nominal value. However, the frequency will not be able to recover to its nominal value without any supplementary action. For the power system to reach its nominal frequency again; there must be intentional increase in active power output of the system via assigning new power setpoints to some units in the system in order to recover system frequency back to its nominal value. By doing so, primary frequency control reserves will be released and the system will be ready for another disturbance.

Since the demand in the system changes continuously, change in power output of the generators is a necessity to maintain system frequency at the desired value. This necessity of continuous tracking of the load-generation balance requires the implementation of automatic generation control system (AGC) in the network. This operation is also known as load-frequency control (LFC) [1].

AGC that is implemented in an isolated network, i.e., no tie line connection to another control zone, operates to hold system frequency at its nominal value. In order to have a successful operation for maintaining frequency, integral control is implemented to adjust governor settings of the units that participate in AGC system. Figure 2.10 below, shows the block diagram of the integral control unit implemented.

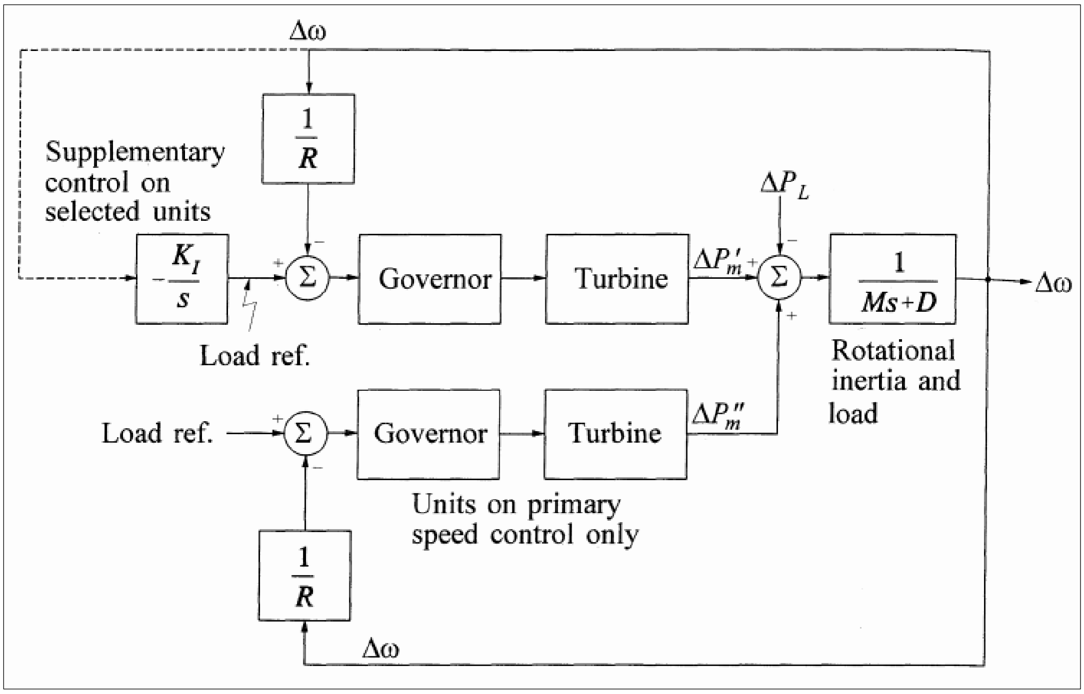


Figure 2.10 Implementation of Integral Control [1]

Parameters used in Figure 2.10 are explained as follows:

R: Speed Droop

M: Inertia

D: Load-Damping Constant

ΔP_L: Change in Load

ΔP_m: Change in Mechanical Power

$\Delta\omega$: Frequency Difference

K_1: Integral Gain

Addition of the integral control affects the load reference point of the generators participating in AGC when ΔP_L has non-zero values. Corresponding change in frequency ($\Delta\omega$) changes load reference with $\Delta\omega$ multiplied by the droop of the generator and changes the units power output. With this operation of the integral control no frequency errors is guaranteed at steady state.

Secondary control (AGC) for interconnected systems is a bit more complicated than the secondary control in an isolated area. The main purpose of the AGC system in this case is to maintain power balance in the system within the limits of generation and tie lines and keeping the frequency at its nominal value. Moreover AGC performs on:

- Keeping system in balance,
- Maintaining the power flow on tie lines at scheduled values.

In order to understand the operation of AGC for an interconnected system, an example with two control areas will be convenient. In Figure 2.11 below, electrical equivalent of an interconnected system with two areas is depicted. P_{12} as expressed in Equation (2-3) represents the active power flow from control area 1 to area 2. X_{tie} is the series reactance of the transmission line connecting two areas. Firstly assume a system with primary speed control only as depicted in Figure 2.12 where T represents the synchronizing torque and a positive ΔP_{12} represents active power flow from Area 1 to Area 2.

$$P_{12} = \frac{E_1 E_2}{X_T} \sin(\delta_1 - \delta_2) \tag{2-3}$$

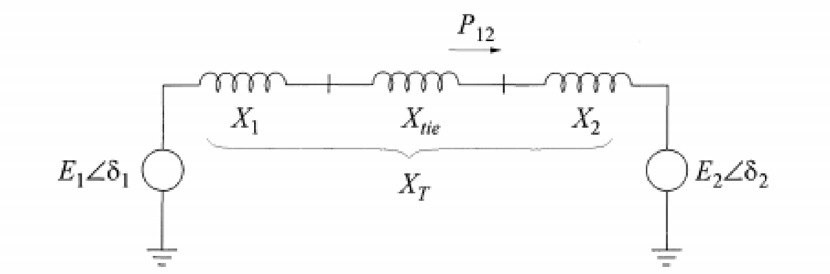


Figure 2.11 Electrical Equivalent of Two Interconnected Area

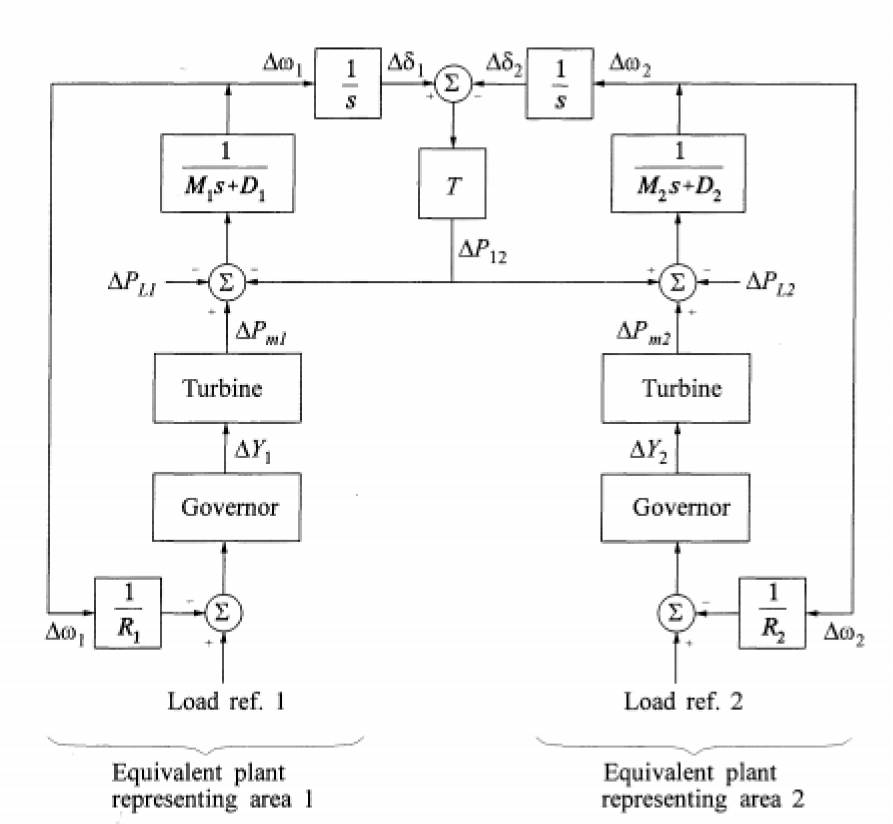


Figure 2.12 Two-area System without AGC [1]

For ΔP_{L1} amount of change in load, deviation of the frequency will be the same for both areas.

$$\Delta f = \Delta\omega_1 = \Delta\omega_2 = \frac{-\Delta P_{L1}}{1/R_1 + 1/R_2 + D_1 + D_2} \tag{2-4}$$

For Area 1, we have

$$\Delta P_{m1} - \Delta P_{12} - \Delta P_{L1} = \Delta f D_1 \tag{2-5}$$

and for Area 2,

$$\Delta P_{m2} + \Delta P_{12} = \Delta f D_2 \tag{2-6}$$

The change in mechanical power depends on droop. Therefore,

$$\Delta P_{m1} = -\frac{\Delta f}{R_1} \tag{2-7}$$

$$\Delta P_{m2} = -\frac{\Delta f}{R_2} \tag{2-8}$$

Then substituting Equation (2-7) in Equation (2-5) and (2-8) to (2-6) following equations are obtained:

$$\Delta f \left(\frac{1}{R_1} + D_1\right) = -\Delta P_{12} - \Delta P_{L1} \tag{2-9}$$

$$\Delta f \left(\frac{1}{R_2} + D_2\right) = \Delta P_{12} \tag{2-10}$$

Solving Equations (2-9) and (2-10) for Δf and ΔP_{12} results as the following:

$$\Delta f = \frac{-\Delta P_{L1}}{\left({}^{1}\!/_{R_1} + D_1\right) + \left({}^{1}\!/_{R_2} + D_2\right)} = \frac{-\Delta P_{L1}}{\beta_1 + \beta_2} \tag{2-11}$$

$$\Delta P_{12} = \frac{-\Delta P_{L1}\left({}^{1}/_{R_2} + D_2\right)}{\left({}^{1}/_{R_1} + D_1\right) + \left({}^{1}/_{R_2} + D_2\right)} = \frac{-\Delta P_{L1}\beta_2}{\beta_1 + \beta_2} \qquad (2\text{-}12)$$

Where β_1 and β_2 represents the overall frequency response characteristics of Area 1 and Area 2, respectively. Variation in load in Area 1 is illustrated in Figure 2.13.

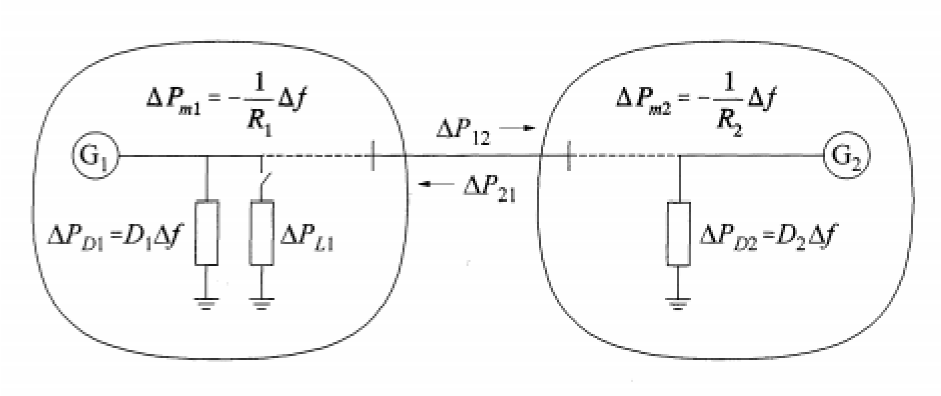


Figure 2.13 Variation in Load in Area 1 [1]

Changing the load in Area 1 by ΔP_{L1} amount decreases the frequency by Δf and results in a tie line flow of ΔP_{12}. The equations derived above constitute the basics of frequency control of interconnected areas. After adding AGC control blocks to two areas, block diagram of the complete control system is shown in Figure 2.14.

Summation of power exchange on interconnection lines and deviation in frequency, which is weighted by bias factors B_1 and B_2 for Area 1 and Area 2 respectively, forms the signal for AGC reaction. This signal is known as Area Control Error (ACE). No matter what the values of bias factors, both ACE_1 and ACE_2 are zero at steady state operation. Bias factors change the initial response of the AGC systems. Following equations defined the ACE and bias factors for each area;

$$ACE_1 = \Delta P_{12} + B_1 \Delta f \tag{2-13}$$

where,

$$B_1 = \beta_1 = {}^{1}\!/_{R_1} + D_1 \tag{2-14}$$

And for Area 2,

$$ACE_2 = \Delta P_{21} + B_2 \Delta f \tag{2-15}$$

where,

$$B_2 = \beta_2 = {}^{1}\!/_{R_2} + D_2 \tag{2-16}$$

As stated before, irrespective of the bias factors, steady state errors for ACE for both areas are zero. However, bias factors determine the initial supplementary generation from one area to another. Assume B_1 and B_2 are equal to each other and there exists a deviation in frequency with Δf amount. Corresponding ACE signals for both will be the following;

$$ACE_1 = \Delta P_{12} + B_1 \Delta f$$

$$= \frac{-\Delta P_{L1}}{\beta_1 + \beta_2} (\beta_1 + \beta_2)$$

$$= -\Delta P_{L1}$$

and similarly,

$$ACE_2 = \Delta P_{12} + B_2 \Delta f$$

$$= \frac{-\Delta P_{L1}}{\beta_1 + \beta_2} (-\beta_2 + \beta_2)$$

$$= 0$$

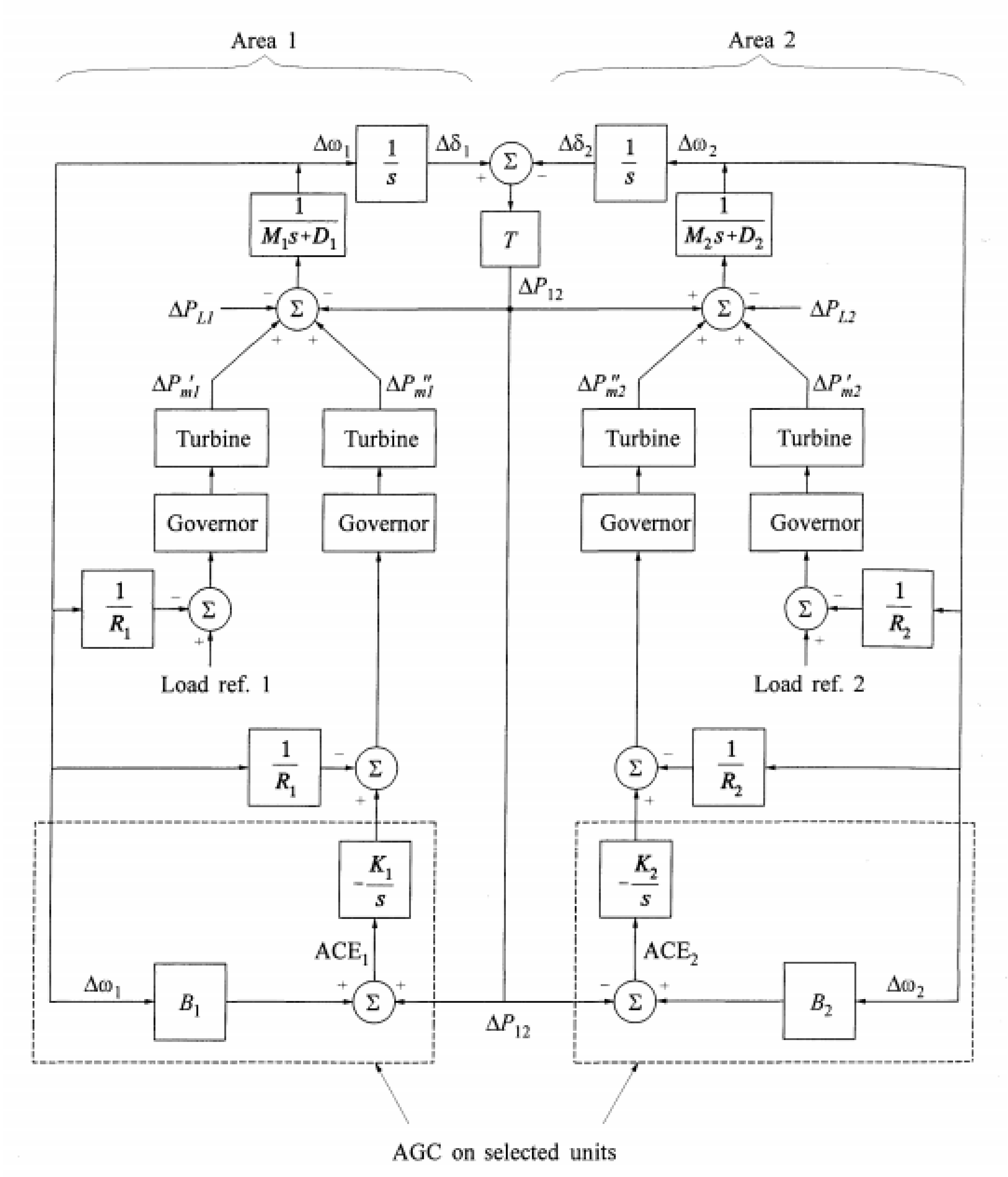


Figure 2.14 Two-area System with AGC [1]

This means that for a load change in Area 1, Area 2 will not take any supplementary secondary control action. But assume another case where B_1 and B_2 are set to twice of their frequency response characteristic (β_1 and β_2). ACEs for both areas this time appear to be the following:

$$ACE_1 = \Delta P_{12} + B_1 \Delta f$$

$$= \frac{-\Delta P_{L1}}{\beta_1 + \beta_2} (2\beta_1 + \beta_2)$$

$$= -\Delta P_{L1} \left(1 - \frac{1}{\beta_2}\right)$$

and for Area 2,

$$ACE_2 = \Delta P_{21} + B_2 \Delta f$$

$$= \Delta P_{21} + 2\beta_2 \Delta f$$

$$= \frac{-\Delta P_{L1}}{\beta_2}$$

In this case, load change in Area 1 is observable from Area 2 and supplementary secondary control action is realized by Area 2 as well. However in steady state condition, this supplement of power will be backed off.

Due to concerns from instability point of view, bias values should not be significantly greater than β of areas. It must be chosen according to the natural governing response of the system [4]. In other words, B is a value that corresponds to the average power output change of a system when frequency of the system changes by 1 Hz in the observed cases.

Implementation of the AGC system to control areas requires some additional actions. In Figure 2.15, implementation of an AGC system is presented.

Generally, the ACE signal is filtered and smoothed ACE signal, SACE, is used for regulation. The idea behind this filtering is to prevent wearing of generator rotors and valves in response to very fast random changes in ACE. This is due to the fact that response of generators to such variations does not help to reduce ACE [1].

After obtaining SACE signal, responses of the generators are adjusted according to the regulating and economic allocation algorithm used by the system operators which is the last action of the AGC system.

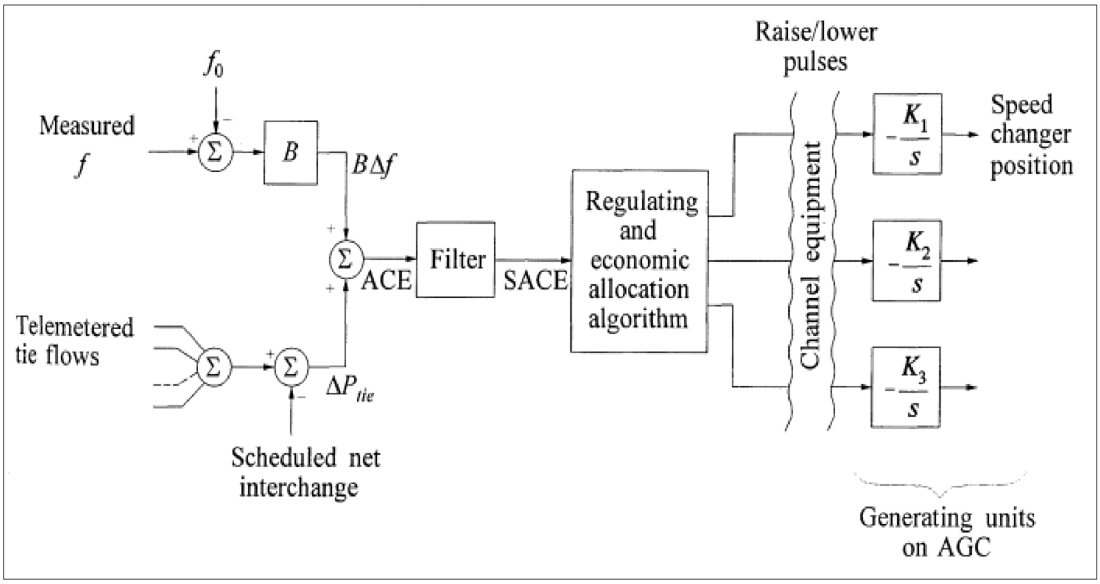


Figure 2.15 Implementation of AGC System

AGC operation is realized by sending set point signals to the generators participating in the control. Therefore performance assessment of AGC system is highly associated with the individual performance of the generating units. If generator units' responses to signals coming from AGC system become faster, overall performance of AGC grows better [5]. Therefore; generator type and characteristics in AGC system becomes very important. Some typical values for regulation speed of different types of units are presented in percentage of rated power per minute below [2]:

- Gas/Oil units : 8%
- Coal/Lignite units :2-4%
- Nuclear units :1-5%
- Hydraulic units :30%

Evaluation of secondary control performance for a system that is subject to a large disturbance is realized with using trumpet curves which are defined by the severity of power mismatch in the system [2]. A typical response of secondary control is illustrated in Figure 2.16.

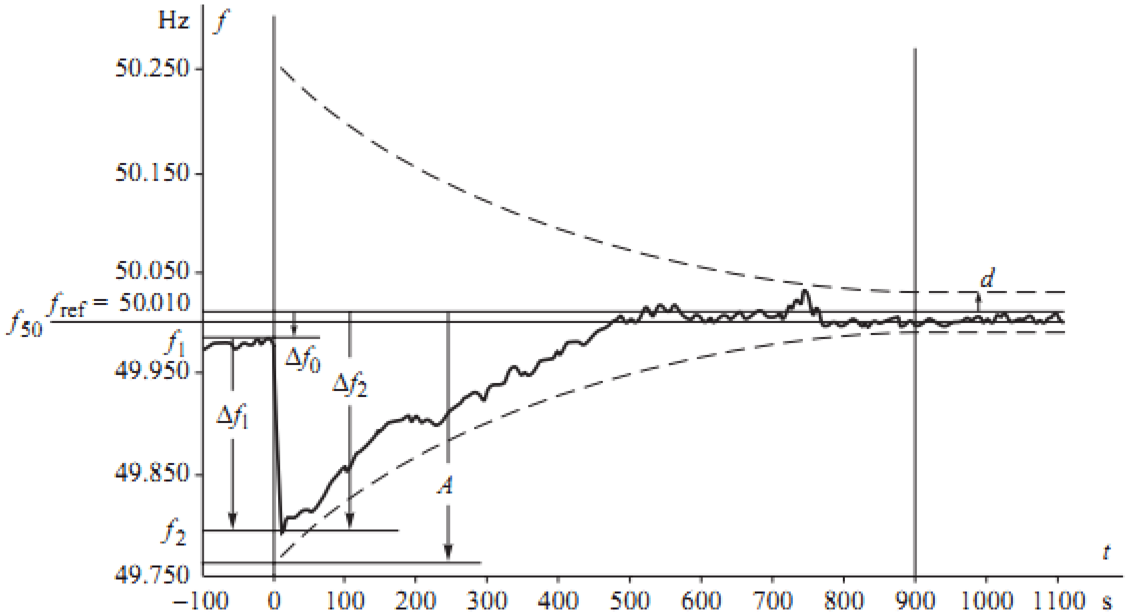


Figure 2.16 Typical Response of AGC System [2]

2.2.2.3. Tertiary Frequency Control

Tertiary control is much slower when compared to primary and secondary control. Generally it is achieved manually by changing power outputs of units by the system operator. By utilizing tertiary control following objectives are aimed:

- Releasing secondary reserves when necessary in order to have adequate amount of reserve at all time,
- Distribution of secondary reserve by means of economic preliminaries.

Changes may occur as follows:

- Taking a generator in or out of service,
- Redistribution of already allocated secondary reserve capacities among participants of AGC,
- Rescheduling the power exchange through tie lines,
- Load control via load-shedding.

2.2.2.4. Time Control

ENTSO-E (formerly UCTE) states that, difference between synchronous time and universal time coordinated must not exceed 30 seconds. It is reasonable to apply time control in periods of uninterrupted interconnected operation in which synchronous time hold the same value for all areas.

2.2.3. Frequency Control Mechanism in Turkey

Primary frequency control is an obligation for power plants with the installed capacity of 50 MW and above. Therefore governing systems must exist in all power plants. As mentioned previously in this chapter, governing action is generally proportional with the speed droop characteristic. The decision regarding the droop characteristic is decided by Turkish Transmission System Operator, TEİAŞ, between %4 and %8.

Primary frequency requirement for the eligible power plants is %1 of the installed capacity. However this liability can be transferred to other power plants in the system via bilateral contracts between the generation companies (GENCOs). Moreover, GENCO can distribute this liability inside the portfolio of power plants it has [6].

Secondary frequency control action is realized by AGC in Turkey. According to the grid code power plants with the installed capacity above 100 MW must be capable of participating in secondary frequency control [7]. Exceptions hold for the following power plants:

- Run-Off River Type Hydraulic Power Plants
- Wind Power Plants
- Solar Power Plants
- Wave Power Stations
- Tidal Power Plants
- Co-generation Power Plants
- Geothermal Power Plants
- Power plants that are installed before the release of the above mentioned grid code.

Moreover power plants satisfying the above requirements must apply to TEİAŞ to sign ancillary service agreement and participate in secondary frequency control upon request.

Frequency control in Turkey became an important issue after Turkey's application to ENTSO-E. On 18 September 2010 the Turkish networks successfully synchronized with the European network via 400 kV transmission lines to Bulgarian and Greek networks [8]. The procedure of becoming a full member of ENTSO-E requires successful completion of 3 phases which can be explained as followings:

- Phase 1: Stabilization period with no scheduled exchange of energy.
- Phase 2: Non-commercial energy exchange with Bulgarian and Greek TSOs in both directions.
- Phase 3: Commercial exchanges are allowed according to mutual agreement of participated TSOs in accordance with the ENTSO-E rules and regulations.

Turkey has successfully completed the first two phase and phase 3 is still on going. Periodic meetings are being conducted between Turkish TSO and ENTSO-E in order to improve Turkish network's performance for full membership.

2.2.4. Difficulties in Provision of Secondary Frequency Control Reserve Support and Solutions

Selection of the power plants for secondary reserve support is decided after the clearance of the day-ahead electricity market. Amount of reserve capacity is decided based on experience of the system operators in National Dispatch Center on an hourly basis. Typically, this amount varies between 750 to 1050 MW within a day. In Figure 2.17 below, amount of secondary reserve capacity for a specific day obtained from National Load Dispatch Center is presented. Difficulty arises when allocating the decided amount of reserve among 3 GW of available capacity in most economic manner. Handy calculations require too much time besides bringing the risk of missing the most economical way of allocation. Therefore an algorithm that is capable of selecting participating units in the most economic manner for the specified amount of reserve requirement is needed to be developed.

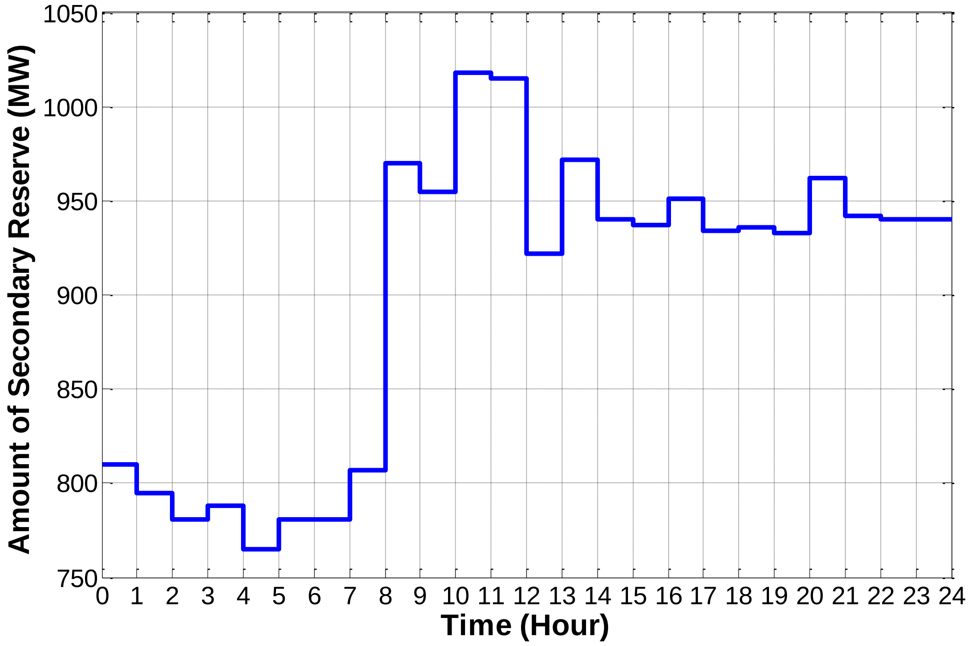


Figure 2.17 Amount of Secondary Reserve Capacity on Hourly Basis

Another challenge is the determination of the amount of secondary reserve requirement for the next day systematically on an hourly basis. In order to achieve it, dynamic model representing ENTSO-E region including Turkish network and power plants contributing to Turkish AGC system is used to simulate the system dynamically. In order to utilize dynamic simulation load disturbance data and participation list of the units to AGC system with corresponding amount of secondary reserve supports are required.

Load disturbance test data are formed by using electric arc furnace demand curves. Electric arc furnaces (EAFs) create the most severe disturbances upon the performance of AGC system [9]. Therefore it is assumed that using active power demand of EAFs is sufficient to represent the disturbance for the network. Detailed information regarding EAFs is presented in Chapter 4.

In Figure 2.18, pink line shows the demand of EAFs in Turkish grid and black line shows the ACE. Measurements are taken from SCADA. The correlation between these two lines support the assumption stated above.

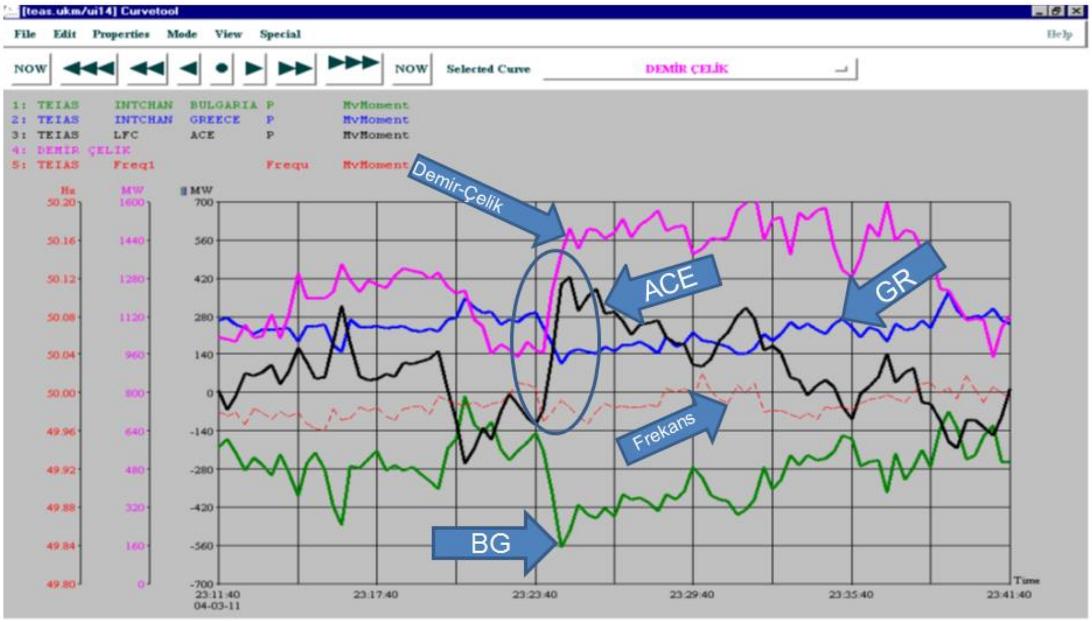


Figure 2.18 Effect of EAFs on ACE [9]

In this thesis study, an iterative algorithm to determine the amount of reserve with minimum cost while satisfying the ENTOE-E criteria regarding Area Control Error (ACE) is developed. Cost minimization of the reserve support is conducted based on the price bids of the power plants participating in AGC system in the day-ahead electricity market. Satisfaction of ACE criteria is validated by dynamic simulations of a simplified ENTSO-E dynamic model. As a result of these studies, amount of reserve to be held on an hourly basis is determined in a systematical way for the use of system operators in National Dispatch Center.

CHAPTER 3

PREPARATION OF THE DYNAMIC MODEL AND SOLUTION ALGORITHM

3.1. Automatic Generation Control in Turkey

AGC systems play a very important role in secondary frequency control mechanism as explained in detail in Chapter 2. Since Turkish network is synchronized with ENTSO-E, AGC system implemented in Turkey should carry the specifications required from an AGC system operating in an interconnected area. Therefore AGC system:

- Restores system frequency,
- Restores tie-line capacities to the scheduled value, and,
- Makes the Turkish grid feed its own load.

These above mentioned controls are utilized by means of changing the power output set points of generating units which are participating in AGC system. Block diagram of AGC system is illustrated in Figure 3.1 below.

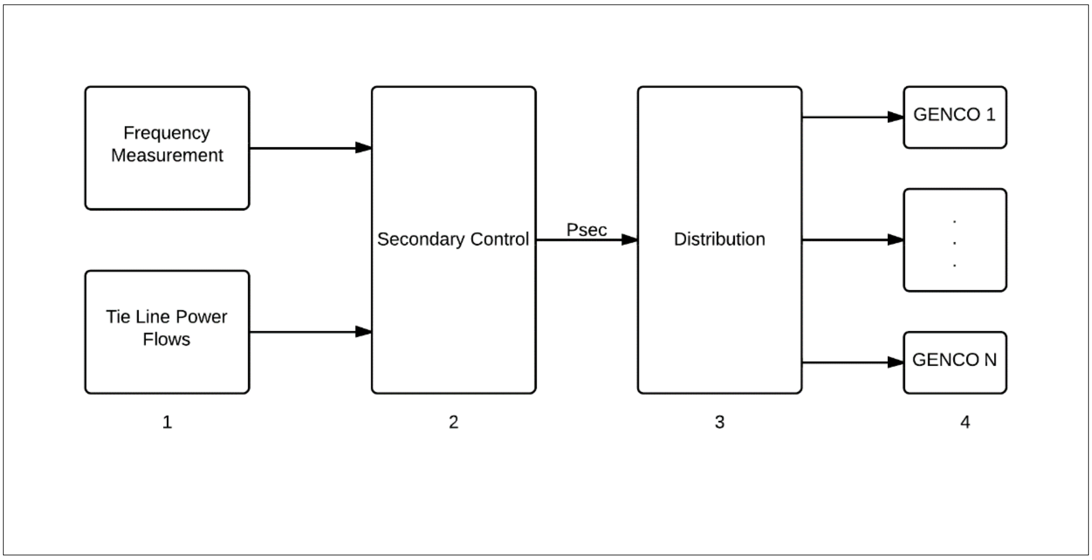


Figure 3.1 Block Diagram of Turkish AGC System

Operation of the AGC can be divided into 4 stages. In the first stage, frequency of the system and tie lines power flows are measured. These two measurements are crucial for the successful operation of the AGC system. Then in stage 2, supplementary action that will be provided by AGC is determined. Resultant output signal, Psec, carries the information regarding the amount of secondary reserve to be utilized. Afterwards, in stage 3, allocation of the Psec amount of power among AGC participants is conducted. Finally at the last stage, corresponding signals in order to change units' power output is sent to GENCOs. As mentioned in previous chapter dynamic simulations in this thesis study is utilized in DigSilent Power System Analysis software. Therefore AGC model is implemented in DigSilent environment. In Figure 3.2 shown below, detailed representation of secondary control block used in DigSilent is presented.

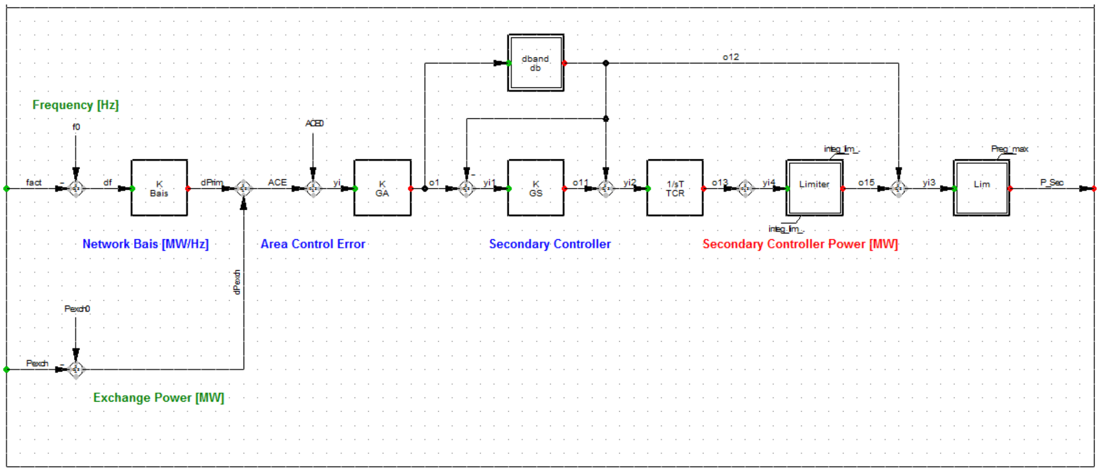


Figure 3.2 Secondary Control Model

More specifically, above structure is the PI (proportional + integral) controller scheme which maintains area control error (ACE) as close to zero. The area control error composed with 2 main signals, namely frequency and exchange power. Calculation of ACE as follows;

$$ACE = \Delta P + K\Delta f \tag{3-1}$$

where,

- ΔP is the exchange power recorded at tie lines
- K is the network frequency bias value
- Δf is the frequency difference

As an output of stage 2, amount of reserve required to be utilized is determined. Corresponding signal is then sent to "Distribution" block which is shown in Figure 3.3.

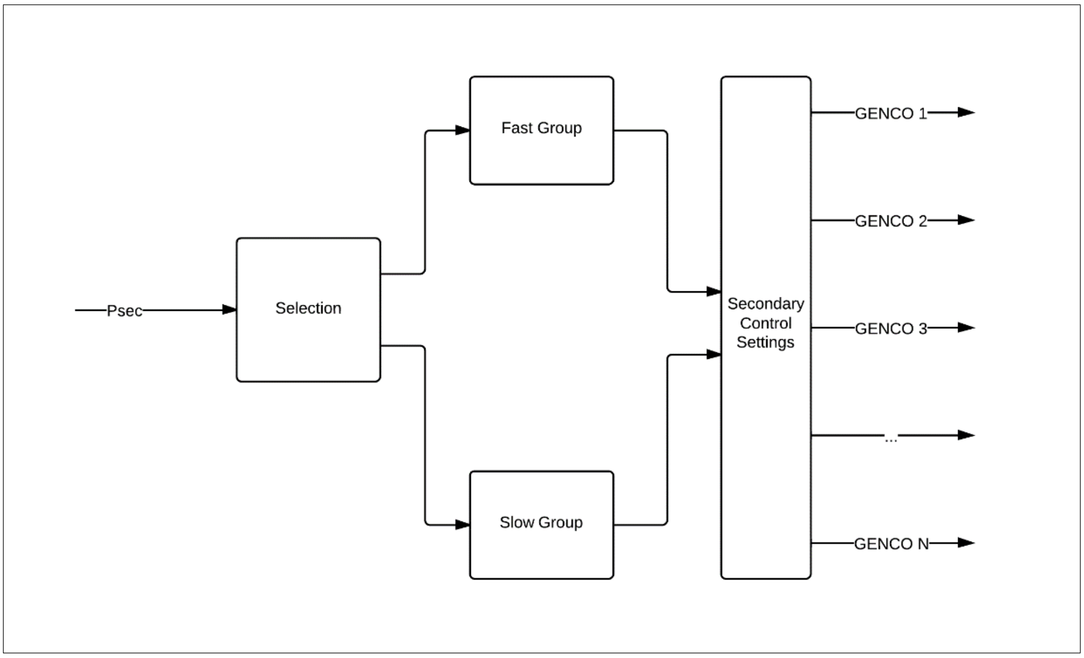


Figure 3.3 Block Diagram of Distribution Block

Psec is the output signal of the secondary control model represented in Figure 3.2 and Psec carries information regarding the amount of power that will be distributed to generators in the AGC system.

In the AGC system there are two groups of reserve, namely fast and slow reserve groups. Upon a disturbance that requires the utilization of all reserve groups, fast reserve group has to be realized in 45 seconds and each generator that has responsibility in fast group must be capable of giving its share in 45 seconds. Amount of reserve in this group is calculated according to the power plants' capability of increasing/decreasing their power output in 45 second time interval. Corresponding values of power output changes determines the contribution of power plants' in fast responsive reserve group. For slow reserve group, time interval is chosen to be 300 seconds [6]. It is expected from each generator to be capable of reaching its maximum reserve capacity after 345 seconds. In order to illustrate it graphically, assume a unit which has A and B amount of reserve for fast and slow group of reserve respectively. In Figure 3.4 below, Po is the power output of a generator unit without any secondary reserve realized. Pa – Po, which equals to A, is the value corresponding to fast reserve portion of the total reserve of the generator. Similarly Pb – Pa, which equals to be B, is the amount corresponding to the slow reserve portion and the max reserve capacity of the unit is A + B amount of power.

While realizing the secondary reserve, at first, fast reserve capacity is utilized in order to response to disturbance more quickly. When there is no available reserve in fast group, then slow group of reserve activated and signals are sent to AGC participants accordingly.

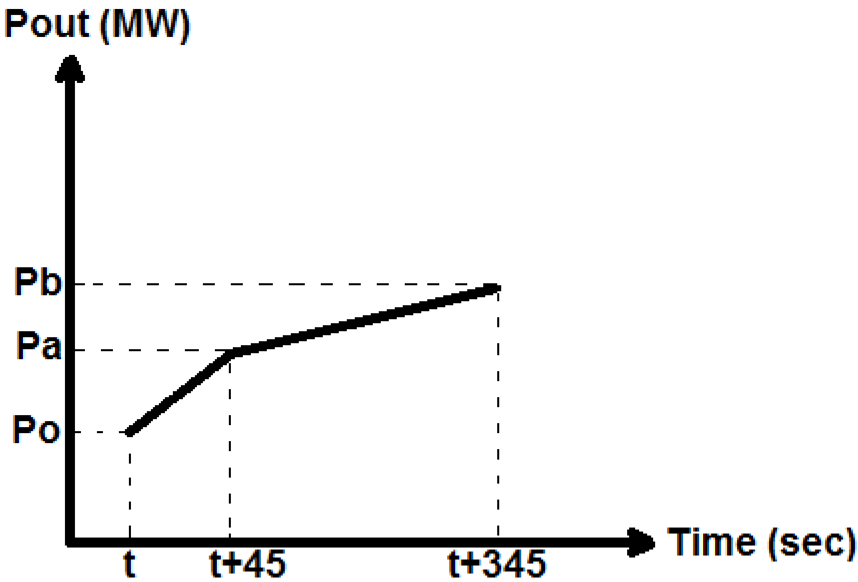


Figure 3.4 Power Output of a Generator Unit in AGC

Each generator has contribution to both fast and slow reserve groups. These amounts are determined by system operator regarding the ramp up and ramp down capabilities of the power plants with site tests. In “Selection” block in Figure 3.3 total capacity of fast and slow reserve groups are stored for that hour of operation. At first, fast reserve group is activated according to coming signal Psec. After the maximum capacity of fast reserve group is reached, Selection block starts to allocate reserve from the slow group as well.

Signals going out from Fast Group and Slow Group blocks are sent to “Secondary Control Settings” block. In this block amount of reserve allocated to each power plant is decided by summing the corresponding amounts of contribution to fast group and slow group reserve of that power plant. Afterwards, secondary control signal of each plant is determined and sent to associated power plant.

Finally in Figure 3.5 below, block diagram of GENCO blocks is shown. In these blocks, amount of reserve share of the GENCO is distributed to the units of power plant that are in operation. By cascaded operation of the 4 main stages, successful operation of AGC is realized.

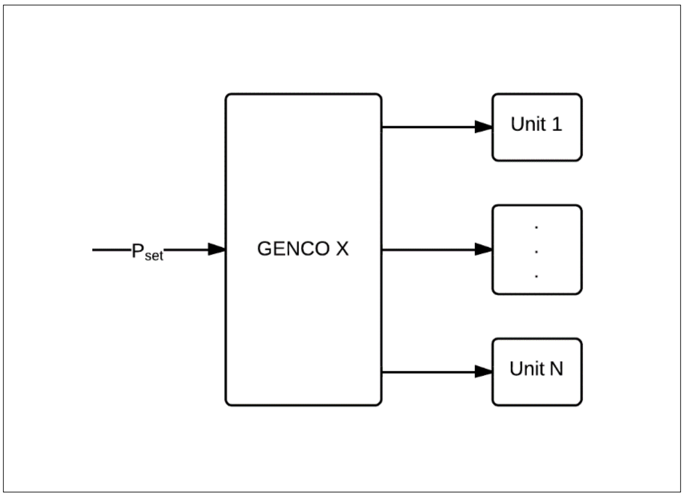


Figure 3.5 Block Diagram of Power Distribution to Units

3.1.1. ACE Performance Criteria from ENTSO-E Point of View

After successful connection of Turkish electricity grid with European electricity network, secondary control performance of AGC in Turkey improved significantly. In order to assess the performance of the AGC system some statistics are reported by TEİAŞ. Reports are grouped into two categories, namely; daily reports and monthly reports.

Daily reports provided by TEİAŞ include statistics for frequency deviation, unscheduled power exchange deviation and behavior of secondary control and statistics for ACE. Calculating the daily statistics of frequency deviation is performed with the following equations:

$$\Delta f_i = f_i - f_s \tag{3-2}$$

where f_s is the scheduled frequency, set on the load frequency controller and f_i is the measured frequency at time instant i.

$$\Delta f_{avr,day} = \frac{1}{n}\sum_{i=1}^{n}(f_i - f_s) \tag{3-3}$$

where n=43200 (measurement period of 2 seconds for 24 hours) and finally standard deviation of Δf shall be calculated as follows:

$$\sigma_{\Delta f,daily} = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(f_i - f_s)^2} \tag{3-4}$$

For daily statistics of unscheduled exchange deviation, formulation is as follows:

$$\Delta P_i = P_{meas,i} - P_s \tag{3-5}$$

where P_s is the scheduled program and $P_{meas,i}$ is the sum of recorded measurements of the power flows in the interconnection lines with the sign convention '+' representing the export from Turkey while '-' holds for import to Turkey.

Mean value of the unscheduled exchange deviation is calculated as follows:

$$\Delta P_{avr,day} = \frac{1}{n}\sum_{i=1}^{n} \Delta P_i \qquad (3\text{-}6)$$

where n=43200 for a measurement period of 2 seconds as in the case for frequency performance measurements and similarly:

$$\sigma_{\Delta P,daily} = \sqrt{\frac{1}{n}\left(\sum_{i=1}^{n} \Delta P_i^2\right) - \Delta P_{avr,day}^2} \qquad (3\text{-}7)$$

On the other hand, in order to assess the behavior of secondary control, a comparison between mean values of frequency and the unscheduled exchange deviation is made for every five minutes. These mean values are calculated as the average of the measurements recorded every 2 seconds during every period of 5 minutes.

$$\Delta P_{avr,5\,min} = \frac{1}{n}\sum_{i=1}^{n} \Delta P_i \qquad (3\text{-}8)$$

and

$$\Delta f_{avr,5\,min} = \frac{1}{n}\sum_{i=1}^{n} (f_i - f_s) \qquad (3\text{-}9)$$

The behavior of the secondary control for a five minute period is assessed as positive when the signs of the two respective above mean values are opposite. Alternatively, the behavior of the secondary control for a five minute period is assessed as negative when the signs of the two respective above mean values are the same. It is noticed that when the absolute of the above described mean value of unscheduled power deviation is smaller than 10 MW then there is no assessment ("non-usable"). Finally, statistics for the percentage of 5 minutes periods with positive behavior, negative behavior and non-usable behavior are prepared.

For the daily statistics of ACE, ACE is calculated by 2 seconds average values of frequency and power exchange as follows as stated in Equation (3-1):

$$ACE = \Delta P + K\Delta f$$

where K denotes the network bias factor and chosen to be 2256 for Turkey. Selection of K factor is important in order to make a control area respond to disturbance in its own control area only. Therefore for each control area it must be chosen according to power frequency characteristic of the electricity grid, i.e. K amount of generation failure will decrease frequency by 1 Hz in the control area. However, this factor is changing according to generators in service which are changing continually. Changing the K factors continually uncoordinated in the synchronous area will create greater discrepancies rather than choosing constant values that differ from the actual power frequency characteristics [3].

Average value of ACE over a period of one hour is calculated with the following formula:

$$ACE_h = \frac{1}{n}\sum_{i=1}^{n} ACE_i \tag{3-10}$$

and standard deviation of ACE is calculated over a period of one hour is calculated as follows:

$$\sigma_{ACE,h} = \sqrt{\frac{1}{n}\left(\sum_{i=1}^{n} ACE_i^2 - ACE_h^2\right)} \tag{3-11}$$

Number of cases within 24 hours for abs(ACE) >175 MW with observation period of 4 seconds is calculated. The number of these cases is calculated by counting the cases in which the abs(ACE) is bigger than 175 MW for two consecutive periods of 2 seconds (2X2seconds=4 seconds). In particular, the value of absolute ACE is calculated for each measurement period of 2 seconds. Then, for every two consecutive periods the average is calculated and when it is over 175 MW then the respective counter increases by one. The default value of the counter for the first measurement period is zero. Afterwards, the final number of the counter is divided by the 43200 measurement periods of the day and it is expressed in percent. Percentage of abs (ACE) >175 MW must be lower than 11% according to ENTSO-E regulations. Successful operation of a day means successful operation of ach hour individually. Therefore, after performing a dynamic simulation, AGC performance is considered to be satisfactory if % [abs (ACE) >175 MW] < 11 for 4 seconds observation period within the hour.

Similar calculation is done for abs(ACE) > 100 MW for 4 second and 15 minute observations periods. For 15 minute observation period; number of cases abs(ACE) > 100 MW is calculated after taking 15 minute averages of ACE values .The cases in which the abs(ACE) is bigger than 100 MW is counted and divided to 96 measurement periods of the day and expressed in percent. Satisfactory operation limits for 4 second and 15 minute observation periods are 33% and 10% respectively.

Monthly reports regarding the assessment of AGC performance is prepared in a similar way as it is done for daily statistics reports. Sections providing information about frequency deviation, unscheduled power exchange, behavior of secondary control on monthly basis and statistics of ACE.

$$\Delta f_{avr,month} = \frac{1}{n}\sum_{i=1}^{n}\left(\Delta f_{h\,i}\right) \tag{3-12}$$

where n equals to number of hours in a month (e.g. 720 for a month of 30 days). For frequency deviation, calculation method is as follows:

$$\sigma_{\Delta f,month} = \sqrt{\frac{1}{n}\left(\sum_{i=1}^{n} \Delta f^{2}{}_{hi}\right) - \Delta f^{2}{}_{avrg,month}} \tag{3-13}$$

Monthly statistics of unscheduled exchange deviation is performed with the averages of the unscheduled exchange deviation for each hour of the month. Mean value of the hourly unscheduled exchange deviation and standard deviation is calculated by the following formulas:

$$\Delta P_{avr,h} = \frac{1}{n}\sum_{i=1}^{n}\left(\Delta P_{h,i}\right) \tag{3-14}$$

$$\sigma_{\Delta P,monthly} = \sqrt{\frac{1}{n}\left(\sum_{i=1}^{n} \Delta P^{2}{}_{h,i}\right) - \Delta P^{2}{}_{avr,h}} \tag{3-15}$$

Assessment of behavior of secondary control is nothing but comparison of five minute average values of frequency and the unscheduled exchange deviation. Average of daily results is foreseen.

Monthly statistics for ACE is performed with the averages of ACE for each hour of the month.

$$ACE_{avr,h} = \frac{1}{n}\sum_{i=1}^{n}\left(ACE_{h,i}\right) \tag{3-16}$$

$$\sigma_{ACE,monthly} = \sqrt{\frac{1}{n}\left(\sum_{i=1}^{n} ACE^{2}{}_{h,i}\right) - ACE^{2}{}_{avr,h}} \tag{3-17}$$

Moreover, the indices σ90 and σ99 of ACE on a monthly basis are also calculated, being the hourly values for which 5% (respectively 0,5%) of both sides of the distribution are outside in case of given mean and standard deviation according to "Regular Report of the Performance of the Primary and Secondary Load-Frequency Control" section of UCTE Handbook [3].

3.2. System Model, Assumptions and Simplifications in Network for Dynamic Simulations

As mentioned in the previous chapter, system model created for dynamical simulations carries great importance in order to obtain reasonable results. Taking into consideration of the high dimension and complexity of power system dynamic analysis, it is wise to classify the problem at interest and creating a system model accordingly. While creating system model, in order to make simplification, assumptions regarding the type of problem up to some degrees are made to reduce the size of the model.

System dynamic simulations in this thesis study are conducted using the dynamical data belonging to the ENTSO-E grid provided by The University of Rostock, TUBITAK MAM Energy Institute and TEİAŞ. This dynamical data carry the information regarding a simplified model of the ENTSO-E region. Each country in this model is represented with several synchronous machines, and these machines have governors, voltage control and power system stabilizers models implemented in order to have successful representation of frequency response of the ENTSO-E grid. Transmission lines between neighboring countries are also modeled. List of equivalent generators used to represent European countries is given in Appendix A.

Turkish grid is connected to the European zone via 3 transmission lines. Two of them connect Turkish grid with the Bulgarian network and the last one provides connection with the Greek network. Connection of the Turkish network with neighboring European countries is shown in Figure 3.6 below.

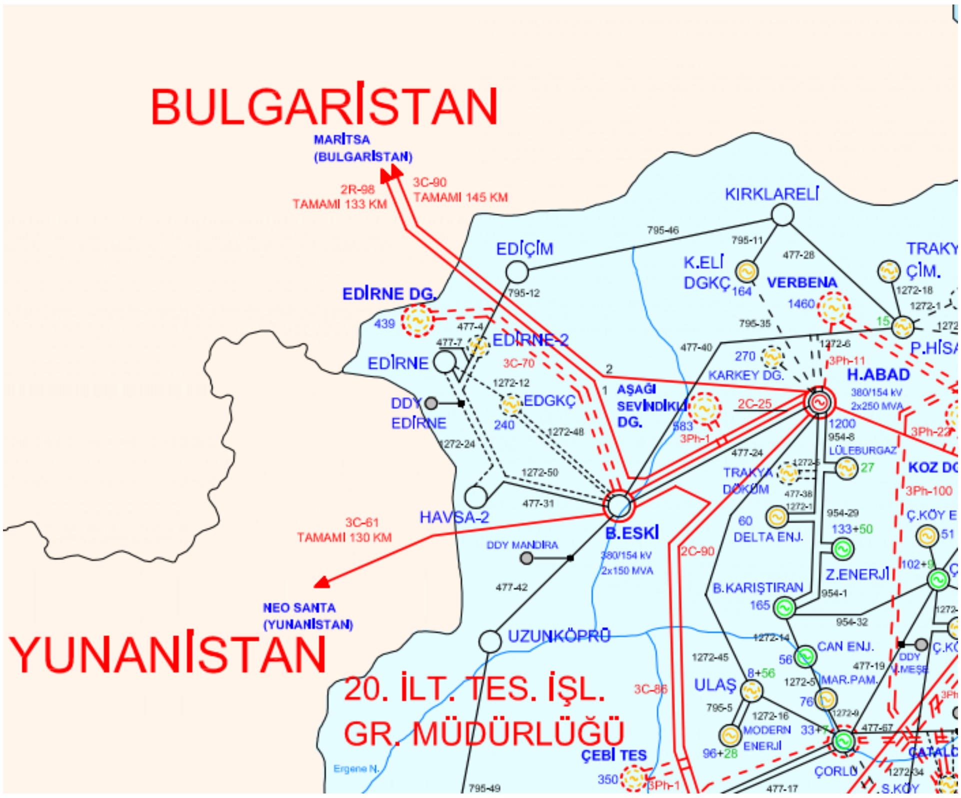


Figure 3.6 Tie Lines between Turkey and Europe

In order to assess the frequency response performance of the Turkish grid, AGC system model explained in the previous section is implemented into the dynamic model. It is assumed that Area Control Error (ACE) performance of the Turkish grid depends mostly on the AGC system. Since primary frequency response is a system wide response over the ENTSO-E region, Turkey's share of primary response upon a disturbance occurred in the Turkish grid is very small since the responses of the grids are proportional with their installed capacities. Therefore, contribution of the primary frequency control in Turkish grid to frequency response is neglected in this study.

Since AGC system plays a key role in the assessment of ACE performance, modelling AGC requires special attention. The ramp up and ramp down parameters of units carry great importance. Because, these parameters determine the capacity of fast and slow reserve groups. Determination of the time for fast and slow group is a tradeoff between the response time of the reserve and reserve capacity. If the time period for the realization of the reserves decreases, total capacity for that group of reserve decreases. In the selection of periods for fast and slow reserve groups, some studies conducted by TUBİTAK, ENTSO-E and TEİAŞ in order to improve Turkish AGC performance. Finally, according to grid code, time periods for fast and slow reserve groups are selected as 45 and 300 seconds respectively.

Besides implementing AGC system, modelling of the network is also important. Single bus common frequency dynamic model (SBCFDM) is used for the representation of Turkish grid [10]. This model is based on the fact that two main important electricity parameter voltage and frequency can be considered as they are decoupled [11]. When it comes to studies conducted regarding the voltage over the network, network topology carries great importance and must be modelled deeply. However, if the primary concern is related with the frequency, topology of the grid can be neglected and all generators in the area can be considered as they are connected to the same bus. SBCFDM is representation of the balance between electrical and mechanical torques which are originated from change in load and speed governors together with AGC control respectively.

There are two critical assumptions behind the SBCFDM model. First one is related with the power transfer capacity of the equipment in network in different load - generation scenarios. From the network planning point of view, transmission system must satisfy the n-1 criteria and violation of this requires enhancement in the network. This implies that loss of an element in the transmission network will not cause any overloading on any of the remaining equipment.

The second assumption is the rigidity of the network. This is defined as the electrical distance between the busbars in a control area. Electrical grids with weak connections may face with inter-area oscillations which can result different frequency measurement in different points of the synchronous network. However in rigid networks this difference in frequency can be neglected. Therefore; with this assumption, frequency of the network is accepted to be the same at every point in the system.

Based on the above mentioned assumptions, SBCFDM can be used in AGC simulations regarding the power exchange and reserve sharing [10]. Therefore units of AGC participants connected to single bus for representation of Turkish grid in the simulation model. With the AGC included, total installed capacity of the on line machines in Turkish grid comes out to be 30 GW. According to a sample day taken from TEİAŞ in July 2014, installed capacity of on-line generators are around 30 GWs with load varying between 19 to 23 GW on hourly basis. Therefore in simulation studies, total load of Turkish grid are chosen to be 20 GW.

In order to reduce system size, determination of the boundaries of the dynamic problem at interest is significant. For further reduction in system size, another important simplification is the representation of the power plants with a one unit only. Case studies showing the difference between multi unit and single unit representations for Adapazarı, Karakaya and Birecik PPs are conducted in order to verify the above mentioned simplification assumption.

In the first case comparison between the responses of single unit and 6 unit representations of Adapazarı NGCCPP is conducted by implementation of a load disturbance measured at Habaş arc furnace with standard deviation equals to 115.67 MW.

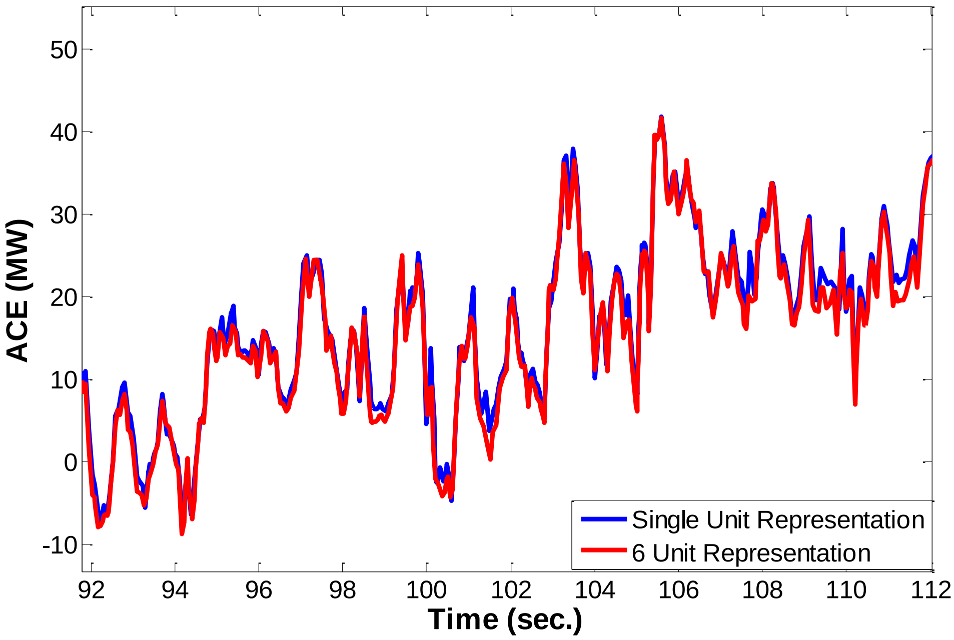


Figure 3.7 Case Study on Adapazarı NGCCPP

All other power plants participating in the AGC are out of service in order to investigate Adapazarı NGCCPP's behavior more clearly. ACE values corresponding to applied Habaş EAF disturbance for the one-unit and multi-unit representations of Adapazarı NGCCPP are shown in Figure 3.7. By assessing those two behaviors, Adapazarı NGCCPP's response for single unit and multi unit representations can be assumed the same.

Similar study is conducted to investigate the response of single unit and multi unit representations of Karakaya HPP as well. For system disturbance, Habaş arc furnace load data obtained from phasor measurement unit are used. Figure 3.8 shows the resultant ACE curves for both cases. Like in the previous case study, response of the both cases can be assumed to be same.

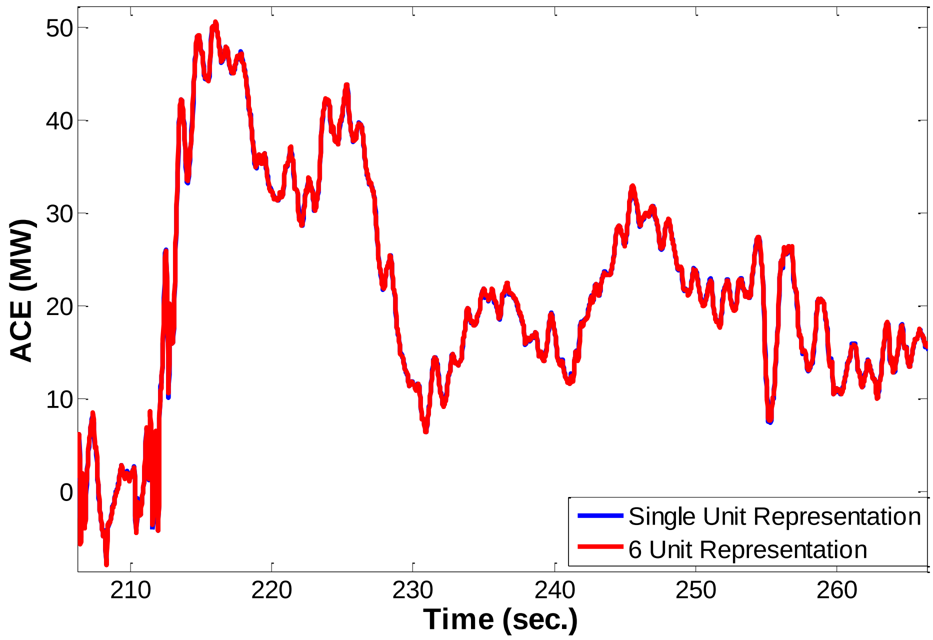


Figure 3.8 Case Study on Karaka HPP

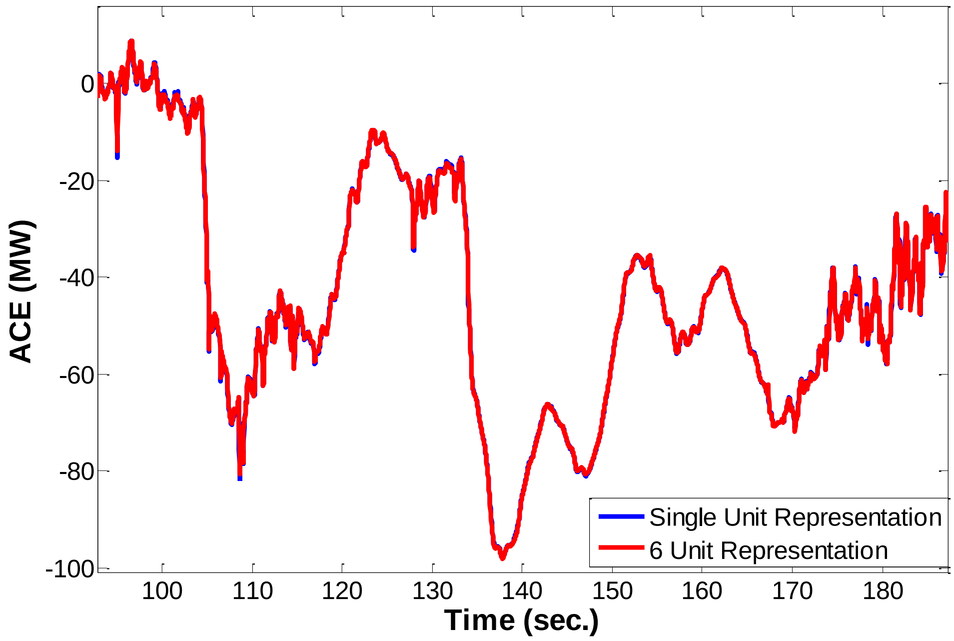


Figure 3.9 Case Study on Birecik HPP

Finally same study is repeated for Birecik HPP. Corresponding response of Birecik HPP that support single-unit representation assumption of power plants is shown in Figure 3.9. Therefore all power plants are represented by their one-unit equivalents in the system model.

Arguments and inferences made throughout this thesis study are based on simulations conducted in DigSilent power system analysis tool. Therefore verification of the used model is very important. Without verification of the used model, outcomes of the study lose its plausibility.

Model verification study was conducted by TUBİTAK-UZAY in 2010 [12]. In that study, real time measurement data of Iskenderun EAF disturbance were utilized. This disturbance occurred in 29.09.2010 in the electricity network. Corresponding responses of Ataturk and Karakaya HPP's were provided by National Load Dispatch Center. Atatürk and Karakaya Power Plants with 700 MW of secondary reserve capability constitute more than 20% of the total system capacity of Turkish grid. This fact is the most important reason behind the selection of power plants to use in the model verification study.

Measurement file contains both power output and power set point of the above mentioned hydraulic power plants at the moment of disturbance. Following figures, Figure 3.10 and Figure 3.11 illustrates the correlation between the model used in simulations and the real responses of the Atatürk and Karakaya power plants, respectively.

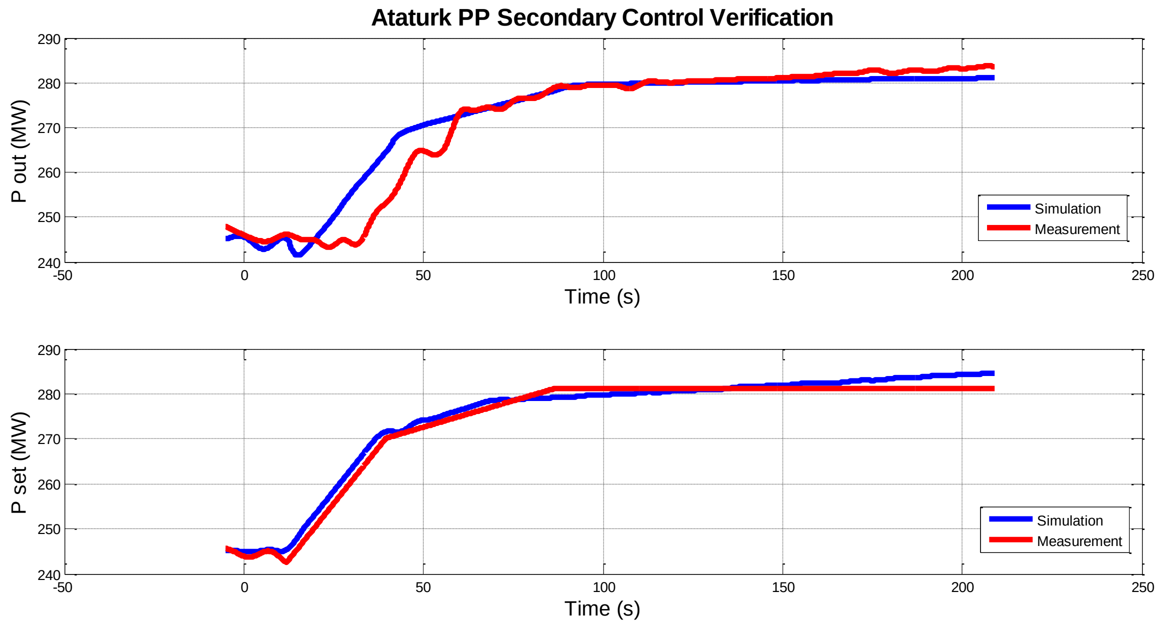


Figure 3.10 Verification result of Atatürk HPP

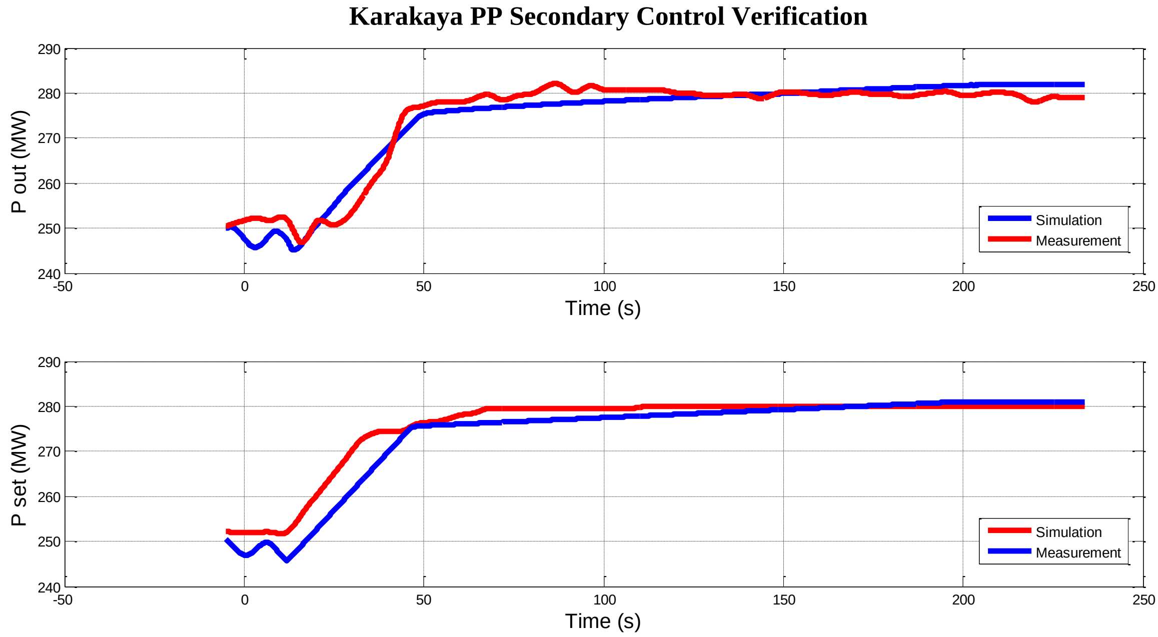


Figure 3.11 Verification result of Karakaya HPP

Currently more than 45 power plants operates in AGC system, however 28 of them is modeled for this thesis study. List of power plants modeled is presented in Table 3.1 below.

Table 3.1 Power Plants Modeled for Dynamic Analysis

Plant ID	Type	Fast Group Reserve (MW/Turbine)	Slow Group Reserve (MW/Turbine)	Number of Units	Total Secondary Reserve (MW)
PP1	Hydro	45	5	8	400
PP2	Hydro	45	5	6	300
PP3	Hydro	25	15	4	160
PP4	Hydro	13.5	1.5	4	60
PP5	Hydro	30	2.5	2	65
PP6	CCGT	5	14	(2GT+1ST)	38
PP7	CCGT	5	14	(2GT+1ST)	38
PP8	CCGT	5	14	(2GT+1ST)	38
PP9	CCGT	5	14	(2GT+1ST)	38
PP10	CCGT	5	14	(2GT+1ST)	38
PP11	CCGT	5	14	(2GT+1ST)	38
PP12	CCGT	15	72.5	(2GT+1ST)	175
PP13	CCGT	22.5	16.5	(2GT+1ST)	78
PP14	CCGT	3.75	8.25	(2GT+1ST)	24
PP15	CCGT	3	9.25	(2GT+1ST)	24
PP16	Thermal	3.75	15.25	1	19
PP17	Thermal	3.75	15.25	1	19
PP18	Thermal	3.75	15.25	1	19
PP19	Hydro	0	5	6	30
PP20	Hydro	22	3	3	75
PP21	CCGT	3.75	7.5	(2GT+1ST)	22.5
PP22	CCGT	6.75	17.25	(2GT+1ST)	48
PP23	CCGT	6	8.83	(3GT+1ST)	32.5
PP24	Hydro	14	6	4	80
PP25	CCGT	2	1.66	(12 GT+1ST)	44
PP26	CCGT	5	2	(7GT+1ST)	56
PP27	CCGT	4	8.66	(3GT+1ST)	38
PP28	CCGT	1.5	1.83	(12 GT+1ST)	40

3.3. Selection of AGC Participants with Minimum Cost

3.3.1. Market Mechanism for Secondary Frequency Control in Turkey

After restructuring and vertical unbundling of electrical industry in many countries, an electricity market has been established. In Turkey, operation schedule of power plants on hourly basis for the next day is being decided in the day-ahead market upon the requirements of the market mechanism which is regulated by Turkish Electricity Market Regulatory Authority (EPDK).

Provision of the secondary reserve support is achieved by the system operator after the clearance of day-ahead market for the next day on an hourly basis. This is accomplished by the evaluation of the price bids of GENCOs. There are two types of bids related to the secondary reserve. These are called Load Increment Order (YAL) and Load Decrement Order (YAT). YAL price represents the price in order to increase the generation of GENCO by 1 MW and YAT is the amount of money that GENCO pays back to reduce its generation output by 1 MW. YAL and YAT orders are bidded by the GENCOs in the day-ahead market at the same time with the bids to be committed for next day.

The complexity of the reserve constitution problem arises upon selection of units that will participate in AGC next day. Generally, amount of reserve constituted for the next day in Turkey changes between 750 and 1050 MWs. The maximum capacity of available reserve exceeds 3000 MW as the time being. Nowadays, more than 40 participants give their bids on an hourly basis for the next day. Moreover each participant has different constraints, i.e., minimum-maximum reserve constraints, block bid constraints. It is also possible for the system operator to commit a unit, which is not scheduled for the next day after settlement of the day-ahead market, for secondary reserve support. It is clear that there are many alternative solutions to constitute a secondary reserve capacity of 750 to 1050 MW out of 3 GW. It is almost impossible to calculate all possible combinations and finding out the cheapest available option which differs on an hourly basis.

Moreover it is difficult to decide on the amount of reserve to be constituted for the next day on an hourly basis. Based on their experiences and knowledge, system operators at TEİAŞ decide on the amount of reserve for the next day. However, it is more convenient to model the system and analyzing the performance of AGC with dynamical simulations.

Automatic Generation Control (AGC) system carries a crucial role from stability, safety and economic operation of point of views. Frequency stability is directly correlated with the performance of the power plants participating in the AGC system. One of the most important purposes of AGC systems is maintaining the frequency of the controlled networks and keeping the power flows on the interconnection lines close to the scheduled values as mentioned in Chapter 2.

After the successful establishment of interconnection between Turkish electricity network and ENTSO-E (European Network of Transmission System Operators for Electricity) in 18.09.2010, performance of Turkish grid is still being monitored and studies to improve interconnection performance have still been conducting.

Steel industry in Turkey creates the most severe disturbances upon the performance of AGC system. Moreover volume of the production of steel is still increasing [13]. In Turkish grid considerable amount of arc furnace load is supplied. This means very sharp electric demand changes in order of 100 MWs. An example of such a change is shown in Figure 3.12.

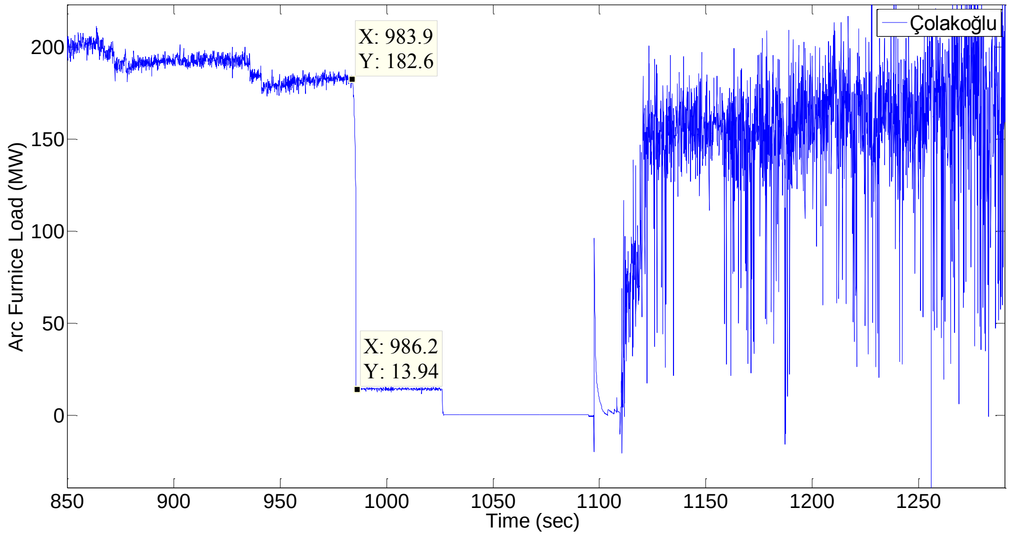


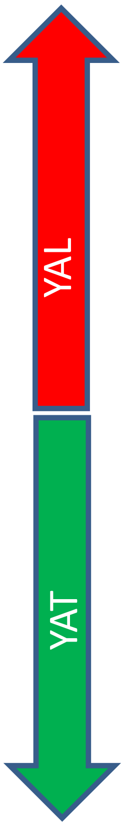
Figure 3.12 Çolakoğlu Arc Furnace Load

This load curve is a part of recorded demand of Çolakoğlu arc furnace on 03.07.2014 between hours 15:30 and 17:30. As can be seen from the figure there is a sharp drop in 2.3 sec with an amount of 170 MW. This figure clearly shows the importance of the secondary reserve control to balance the generation and demand of the network. System operator in the national dispatch center is responsible for constitution of the secondary reserve.

The process starts with the clearing of the market. All GENCOs (Generation Company) place their bids for the next day on an hourly based schedule. GENCOs also provide YAL (Load Increment Order) and YAT (Load Decrement Order) bids on an hourly basis. Unit of both YAL and YAT orders is TL/MWh. Minimum amount for YAL and YAT bids is 10 MW. An example of bidding is shown in Table 3.2.

Table 3.2 Bids of GENCOs

	Price TL/MWh	Amount MWh
15	…	…
14	…	…
…	…	…
3	155	30
2	145	60
1	120	10
1	95	50
2	90	10
3	70	15
…	…	…
14	…	…
15	…	…



GENCOs can place their bids in 15 different levels. However, Energy Market Regulatory Authority (EMRA) states that price difference between 1st and 15th bid cannot change more than %20 percent.

YAL bids for the next level must be equal or greater than previous level of YAL bid. Similarly YAT bids for the next level must be equal or lower than the previous level of YAT bid.

YAL bids must be greater than the market clearing price (MCP) for that specific hour. Likewise, YAT bids must be lower than the MCP of that hour.

After gathering all bids, bids are placed in a merit order starting from the YAT orders. Then system operator, based on his experience, decides the amount of reserve to be selected for each hour of the next day. Amount of reserve allocated changes in day time and night time. But there is no mathematical tool for determining the amount of reserve in current practice in Turkey.

In Figure 3.13 a typical reserve constitution example is shown. Atatürk hydraulic power plant is chosen for this example. In part (a) operating conditions of a unit from Ataturk is shown. P_{min}=200 MW and P_{max}= 300 MW are the rated values for Atatürk HPP's units.

After settlement of the day-ahead market, assume that Ataturk HPP is committed with 1 unit when market is cleared. Power output of a power plant after settlement of the day-ahead market is shown with the KGUP abbreviation.

For a power plant to contribute in the AGC system; that power plant must have the capability of increasing or decreasing its output power by the amount of reserve it is assigned for that specific hour. In part (b), KGUP of the power plant is assumed to be equal to P_{min} of the unit. Therefore under this operating condition, Atatürk power plant does not provide any reserve for that specific hour since KGUP=P_{min} and there is no possible range in the decreasing direction.

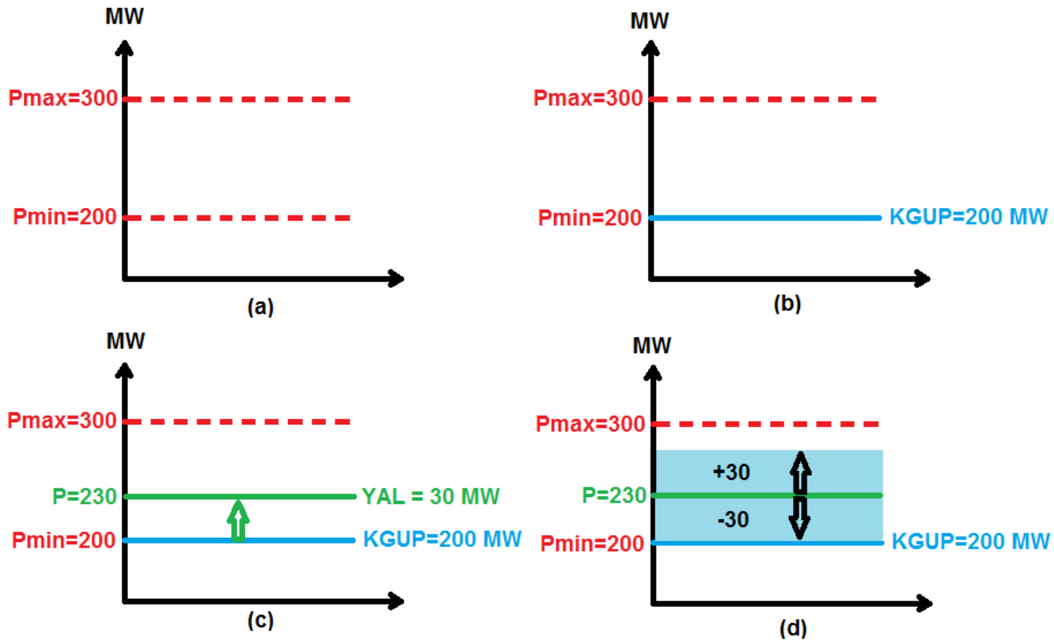


Figure 3.13 Typical Example of Reserve Constitution

In order to allocate reserve from Atatürk HPP operating point of the plant must be changed. This is done by giving YAL and YAT orders to Atatürk HPP. In part (c) of the figure, 30 MW of YAL order is given to Atatürk HPP by the system operator and operating point of the plant is changed to 230 MW.

In part (d) it is shown that Atatürk HPP can provide ∓30 MW of reserve with the new operating point.

It is not always the case like in Atatürk HPP, in some power plants, minimum and maximum operating points while contributing in AGC system is not the same with the operating limits of the unit. In Figure 3.14 it is shown that for a power plant to participate in secondary frequency control, operating point of that PP must lie between the values PRmin and PRmax.

In Figure 3.15, it is shown that GENCO's KGUP is beyond the range of limits to provide reserve support after settlement of the day-ahead market. Therefore YAT order is needed to change the operating point of the GENCO. For the GENCO to hold (PRmax – Po) amount of reserve, corresponding YAT order is (KGUP - Po).

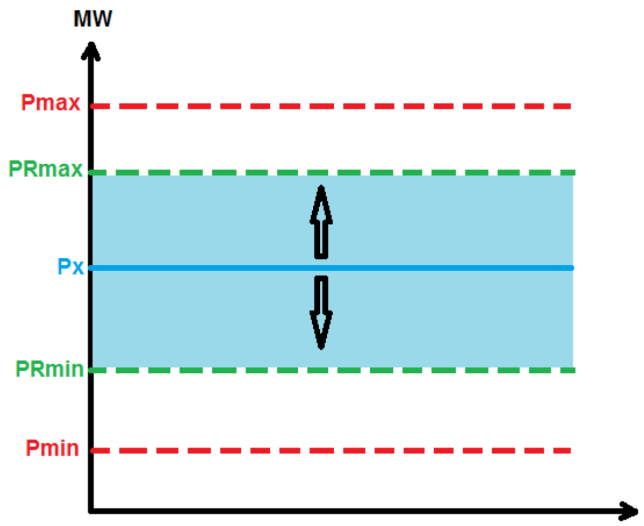


Figure 3.14 Operation Limits for Reserve Support

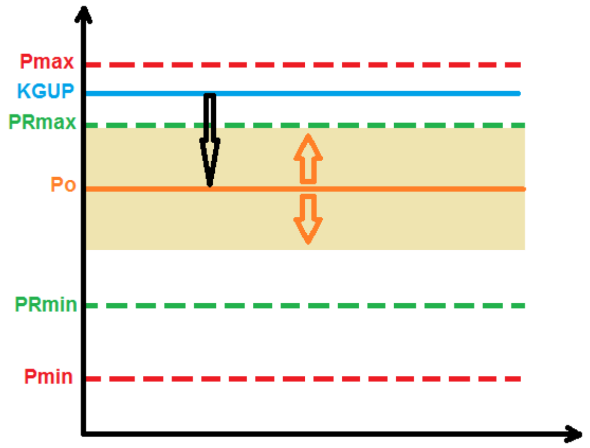


Figure 3.15 Typical Example of Reserve Constitution 2

3.3.2. Price Algorithm upon Secondary Frequency Control Reserve Support

Electricity market is an environment in which GENCOs try to maximize their profit. But when it comes to system operator point of view, system operator tries to minimize the cost of electricity for the operation hour mentioned by selecting cheapest available power plants.

After settlement of the day-ahead market, system operator starts to constitute secondary reserve by giving YAL & YAT orders to GENCOs participating in the secondary frequency control. Main objective of the system operator is to constitute enough reserve on an hourly basis for the next day in most economic manner. Therefore the objective function in Equation (3-18) aims to minimize the cost of constitution of secondary reserve.

$$Minimize\ \{Cost = \sum_{p=1}^{n} YAL_p x YALTO_p - YAT_p x YATTO_p\} \tag{3-18}$$

p: p[th] GENCO giving bids to participate in secondary frequency control

n: Total number of GENCOs

YAL_p: Price of the order to increase GENCO's power output (TL/MWh)

$YALTO_p$: Total amount of order to increase GENCO's power output (MW)

YAT_p: Money collected from GENCO to decrease its power output (TL/MWh)

$YATTO_p$: Total amount of order to decrease GENCO's power output (MW)

Most of the time power plants have more than one unit. So it is within the alternatives for the system operator to choose a unit which is not committed in the day-ahead market but available to participate in the secondary frequency control.

System operator does that by giving YAL and YAT orders. So objective function is to minimize, namely the cost function, must have integer variables representing the selection of available units of power plants that are not in operation after settlement of the day-ahead market. Therefore objective function evolves in a way shown in equation (3-2) below.

$$\begin{aligned} Minimize\{S_p &\left(\sum_{p=1}^{n} R_{p_o}\, x\, YAL_p x I_{yon} + R_{p_o}\, x\, YAT_p\, x\, \left(I_{yon}-1\right)\right) \\ &+\ H_{P_i}(\sum_{p=1}^{np} \sum_{i=1}^{EAUS_p-DUS_p} R_{p_i}\, x\, YAL_p) \\ &+ Q_p\left(\sum_{p=1}^{np} abs\left(GT_p\right) x \left(YAT_p - YAL_p\right)\right)\} \end{aligned} \tag{3-19}$$

Such that:

$$S_p(\sum_{p=1}^{n} Re_{p_o}) + H_{P_i}(\sum_{p=1}^{n} \sum_{i=1}^{EAUS_p-DUS_p} Re_{p_i})\ \geq R_{TOTAL} \tag{3-20}$$

$$S_p(\sum_{p=1}^{n} Re_{p_o}^{T1}) + H_{P_i}(\sum_{p=1}^{n} \sum_{i=1}^{EAUS_p-DUS_p} Re_{p_i}^{T1})\ \geq R_{TOTAL}^{T1} \tag{3-21}$$

$$0 \leq R_{p_o} \leq \max\left\{GT_p, AR_p\right\} \tag{3-22}$$

$$0 \leq Re_{p_o} \leq AR_p \tag{3-23}$$

$$MinU_{p_i} \leq Re_{p_i} \leq MaxU_{p_i} \tag{3-24}$$

$$Re_{p_o}^{T1} = \min\{Re_{p_o}, DUS_p\ x\ MaxT_{p_i}\} \tag{3-25}$$

$$Re_{p_i}^{T1} = min\{Re_{p_i}, MaxT_{p_i}\} \tag{3-26}$$

$$mkud_{p_i} \leq R_{p_i} \leq U_{p_{i,max}} \tag{3-27}$$

where,

S_p: Integer variable, 1 when R_{p_o}>0, 0 otherwise.

R_{p_o}: Amount of order given to pth plant according to GT_p (MW).

I_{yon}: Integer input, 1 when GT_p>0, 0 otherwise.

H_{P_i}: Integer variable, 1 when R_{p_i}>0, 0 otherwise.

$EAUS_p$: Number of units of a power plant that is committed plus available for commitment.

DUS_p: maximum{Number of units that are committed in day-ahead market,1(representing first available unit if plant is not committed in day-ahead market)}.

R_{p_i}: Amount of order given to pth plant's ith unit (MW).

Q_p: Integer variable that is 1 when GT_p is negative and H_{P_1}= 1, 0 otherwise.

GT_p: Amount of order needed to be given to pth power plant in order to get maximum available reserve with the committed units (MW) or to bring next available unit in an operating point in which that unit provides maximum reserve.

Re_{p_o}: Amount of reserve provided by pth power plant with the order R_{p_o}(MW).

R_{TOTAL}: Amount of total reserve requirement (MW).

$Re_{p_o}^{T1}$: Amount of reserve provided that is in regulating range (fast reserve) by pth power plant with the order R_{p_o}(MW).

R_{TOTAL}^{T1}: Amount of total reserve requirement (MW).

AR_p: Amount of reserve provided in response to GT_p order (MW).

$MaxU_{p_i}$: Maximum amount of reserve of pth plant's ith unit (MW).

$MinU_{p_i}$: Minimum amount of reserve of pth plant's ith unit (MW).

$mkud_{p_i}$: Minimum level of stable operation for pth plant's ith unit (MW).

$U_{p_{i,max}}$: Maximum power output of pth plant's ith unit (MW).

$MaxT_{p_i}$: Amount of reserve procurable that is in regulating range (fast reserve) by pth power plant's ith unit (MW).

In order to solve the objective function stated in equation (3-1) MILPROG (mixed integer linear programming) tool of MATLAB is utilized.

In Equation (3-2) second $(H_{P_i}(\sum_{p=1}^{np}\sum_{i=1}^{EAUS_p-DUS_p} R_{p_i}xYAL_p))$ and third part $(Q_p(\sum_{p=1}^{np} abs(GT_p)x(YAT_p - YAL_p)))$ of the equation is applicable for hydraulic power plants only. Because all of the thermic (natural gas fired and coal fired) PPs send bloke bids. Bloke bid is kind of a bid that that power plant is considered as a single unit. Moreover it is the only option to give GT_p amount of order to these plants when they are not committed in the day-ahead market if their participation is wanted.

Third part of the Equation (3-2) is to eliminate the possibility of giving both YAL and YAT orders to a power plant that have a negative GT_p. When a power plant has a negative GT_p value from first part of the Equation (3-2) R_{p_o} amount of YAT order can be applicable. Assume that optimization algorithm has selected that unit and corresponding cost is equal to $R_{p_o}\ x\ YAT_p\ x\ (-1)$. Moreover when algorithm selects another unit from the same power plant, second part of equation (3-2) brings the R_{p_i} amount of YAL order. Total cost is updated to $R_{p_o}\ x\ YAT_p\ x\ (-1) + R_{p_i}\ x\ YAL_p$. In the updated cost $R_{p_o}$is equal to GT_p.

It is not an economic approach to commit a new unit before getting available reserve from the already committed unit. Since it is not practical to give both YAL and YAT orders to a power plant, this contradiction must be cancelled out by the addition of another equation. Without any addition, R_{p_o} amount of power is reduced from R_{p_i}, but YAL and YAT prices are different, so they do not cancel each other. At this point, implementation of third part of the equation, $abs\left(GT_p\right)\ x\ (YAT_p - YAL_p)$ cancels out the YAT order contribution to cost function and final cost becomes $(R_{p_i} - \left(GT_p\right))\ x\ YAL_p$.

The need of such optimization algorithm is to reduce the time of calculating the most economic option. Furthermore hand calculation is too risky to solve the problem due to the high number of variables in objective and constraint equations.

Another important reason of such algorithm is providing a constraint for fast operating reserves. Fast operating reserve plays the most crucial role for reduction of ACE calculations. Because, there is a significant difference between fast and slow reserve groups' response times. While fast reserve capacity of the system can be put into operation in 45 seconds, this time reaches to 300 seconds for the slow part of the total reserve. When we consider the 4 sec average of ACE calculations, it is obvious that fast reserve plays the most important role to satisfy the ACE criteria.

3.4. Optimal Determination and Allocation of Secondary Frequency Control Reserve

Optimization process of the secondary reserve is constituted on an hourly basis according to the bids of GENCOs. The algorithm requires cascaded operation of two simulation platforms, namely; MATLAB and DigSilent. Coordination between these 2 platforms is provided by the developed DigSilent Programming Language (DPL). Figure 3.16 below shows the flowchart of the optimization process.

Optimization process starts with the collection of data from the electricity market and performed on an hourly basis. After the settlement of the day-ahead market, YAL and YAT order bids of GENCOs are taken. According to the created load disturbance scenario for that hour of operation, an initial reserve guess is made. It is chosen between $\pm 15\ \%$ of the peak demand of the created load disturbance data. Afterwards, amount of reserves for further iterations are determined by the algorithm.

Next, constraints of the problem are formed regarding the results of electricity market. Available units, units that are already in operation and their reserve capacity constraints are implemented into the problem formulation. Then problem is converted to mixed integer linear programming problem. Moreover, besides the mentioned constraints above there are two main inputs to MILPROG, namely "total reserve (MW)" and "fast reserve (MW)" inputs that constitutes reserve constraints of the objective function.

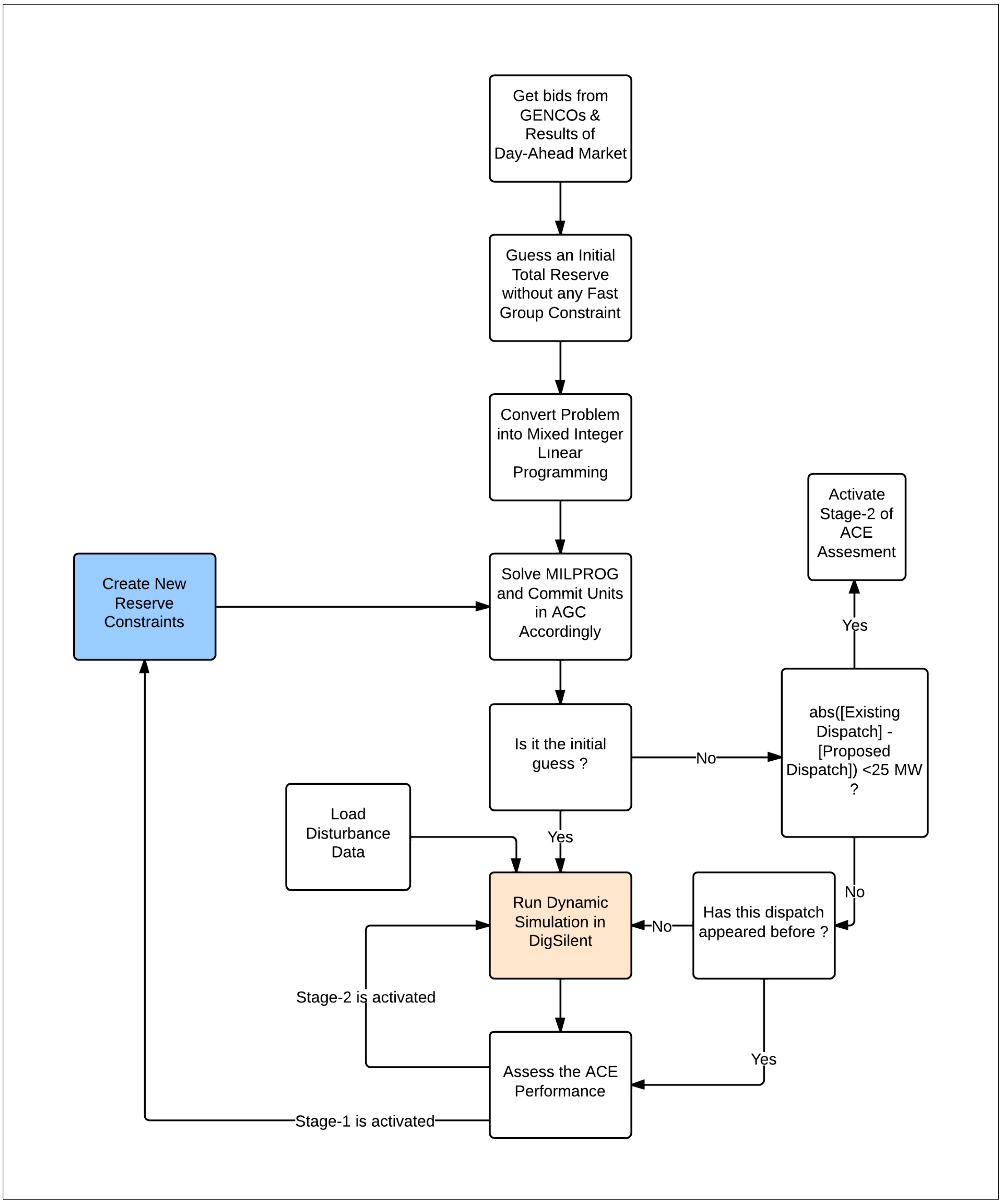


Figure 3.16 Flowchart of Optimization Process

After solving the cost minimization problem via MILPROG, an optimum price is found with the given constraints. Results of the MILPROG algorithm are imported into DigSilent via utilization of the developed DPL code. With this code, on-off state of the units are controlled. Moreover, controller blocks of units are taken in and out of service accordingly. Finally, reserve sharing is done among the utilized units for the AGC system according to resultant commitment for secondary reserve control.

As a next step, dynamic simulation is performed with the created load disturbance test data. These data are formed by using real measurements obtained from of Electric Arc Furnaces (EAFs). Detailed information regarding the load disturbance data is given in Chapter 4. Power exchange on tie lines and system frequency are the results of interest in order to evaluate system performance and calculation of area control error (ACE). Then assessment of AGC performance is made in two stages. Selection procedure for stages is shown in Figure 3.17. If Stage-2 has activated before, algorithm simply choses Stage-2, otherwise Stage 1 is activated.

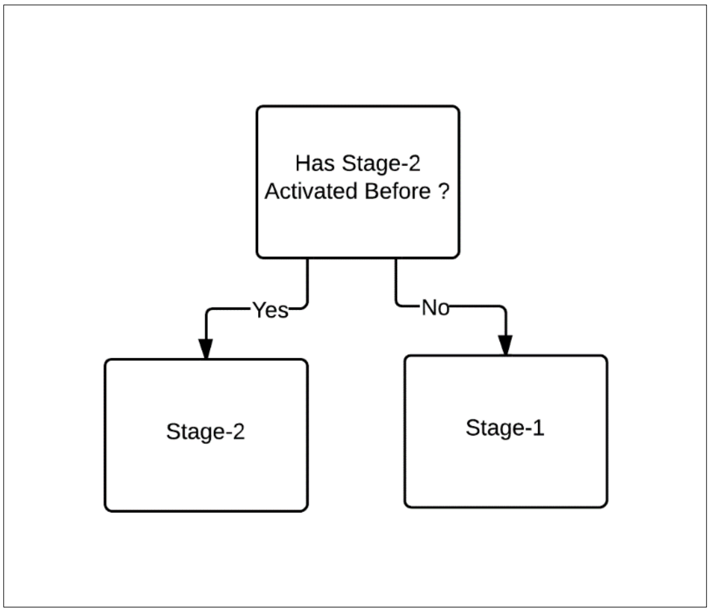


Figure 3.17 Selection of Stages in the Assessment of ACE

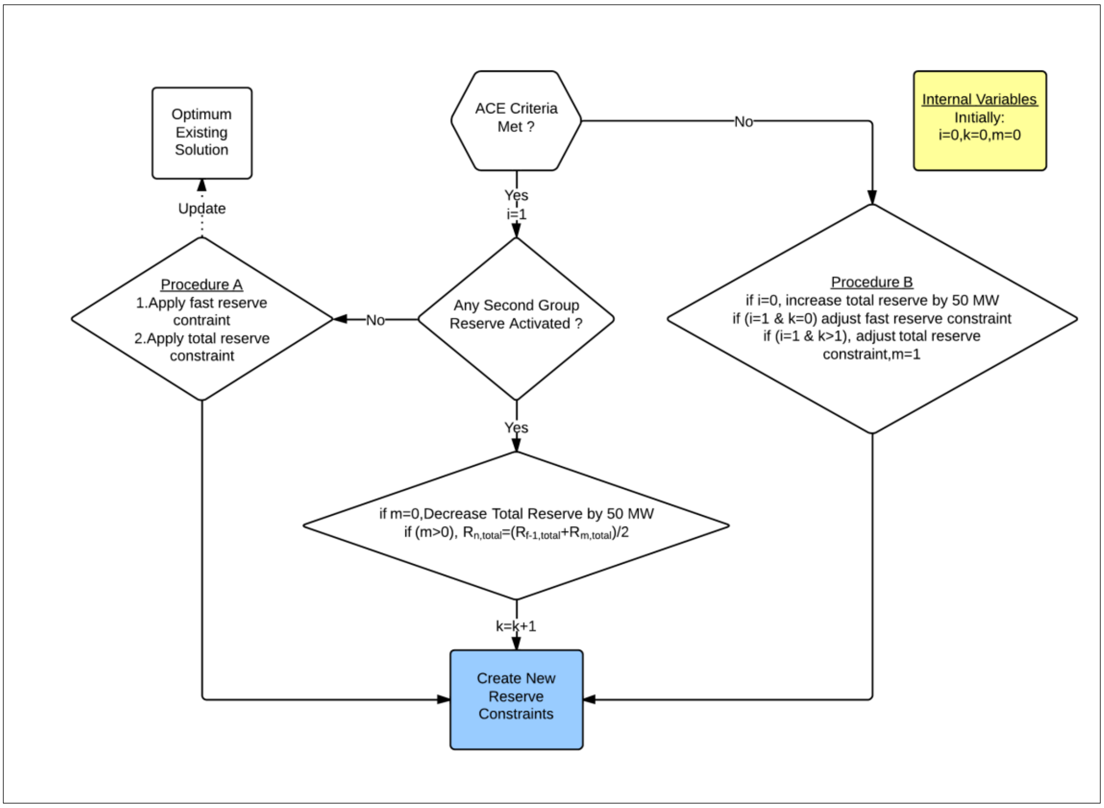


Figure 3.18 Assessment of ACE, Stage-1

Figure 3.18 shows the procedure of the assessment of ACE for Stage-1.First step of the process is to check whether ACE criteria are satisfied or not. There are three integer variables i, k, m which are used to ease the decision making for reserve constraints. Further explanations are made throughout this section. If the system performance is well enough to satisfy the ACE criteria, corresponding solution is kept in the memory as $R_{m,total}$ and $R_{m,fast}$ for total and fast amount of reserves respectively. Also indicator "i" changes to 1 after satisfactory performance of AGC. If system fails to satisfy the ACE criteria, "Procedure B" section is activated.

"Procedure B" section has several operations regarding the states of i, and k integer variables. When ACE criteria are not satisfied with the initial reserve, all indicators remain zero. With this input combination of internal variables, "Procedure B" takes the action of increasing the level of reserve by 50 MW. Then new constraint for total reserve, $R_{n,total}$, is decided.

When ACE criteria are met, i becomes 1 and activation of second group (slow) reserve during the dynamic analysis is checked. If second group of reserve is not activated, process goes into "Procedure A" section. In this section reserve cost is aimed to be decreased. In order to accomplish that "total reserve" and "fast reserve" constraint is manipulated to find an alternative with less cost in MATLAB. As a first step in this section, "total reserve" constraint is entered as 0 and for "fast reserve" constraint; amount of fast reserve allocation of the existing solution, where ACE criteria are met, is utilized. Fast reserve constraint is denoted by $R_{n,fast}$. By doing so, same dynamic response will be obtained from the system since amount of reserve in the fast group does not change. On the other hand, since the amount of total reserve is decreased, cost of the constitution of secondary reserve is decreased. Therefore "Optimum Existing Solution" section is updated with these more economical amounts of reserve, $R_{m,total}$ and $R_{m,fast}$ values are updated accordingly. For further optimization of the price a new constraint $R_{n,total} = R_{m,total}$ is chosen. This guarantees that the resultant commitment will cost less or at most equal to the previous solution with total and fast reserve amounts which are equal to $R_{m,total}$ and $R_{m,fast}$ respectively. Result of the MILPROG algorithm for the latest attempt is kept with variables $R_{f,total}$ and $R_{f,fast}$ for total and fast reserve respectively. These variables are not necessarily to be equal to $R_{n.total}$ and $R_{n,fast}$. Since there are some block bids in the market, resultant reserve amounts may be greater than the constraints of the problem.

Afterwards, MILPROG is executed with the new constraints and dynamic simulation in DigSilent is run again. If ACE criteria are met, again necessities of "Procedure A" are conducted. But if ACE criteria are not met, "Procedure B" section with i=1 and k=0 takes action. With this input combination of integer variables, cost optimization algorithm with new constraints, $R_{n,total} = 0$ and $R_{n,fast} = \frac{R_{m,fast}+R_{f,fast}}{2}$ is executed. After execution of the minimization algorithm values for $R_{f,fast}$ and $R_{f,total}$ are updated according to the result of the cost optimization algorithm. Then dynamic simulation is executed again. If ACE criteria are not met, process continues with “Procedure B”.

When there is a solution with second group of reserve also activated, at first, cost optimization algorithm with total amount of reserve constraint $R_{n,total} = R_{m,total} - 50$ if m equals to zero, then MATLAB and DigSilent is utilized according to the new commitment of GENCOs. Integer variable k becomes 1 as well. If ACE criteria are not met, “Procedure B” with i=1 and k=1 takes place. Cost minimization problem with new constraints, $R_{n,total} = \frac{R_{f,total}+R_{m,total}}{2}$ and $R_{n,fast} = 0$ is executed. After execution of MATLAB $R_{f,total}$ and $R_{f,fast}$ values are updated according to committed total and fast reserve amounts and m becomes 1. Then dynamic simulation takes place.

If a solution exists with secondary reserve group activated with m equals 1, next step for price minimization is to commit units with the new constraints $R_{n,total} = \frac{R_{m,total}+R_{f-1,total}}{2}$ and $R_{n,fast} = 0$. Procedure continues unless a difference between dispatched power of existing solution and proposed dispatch becomes smaller than 25 MW. Then, what remains for $R_{m,total}$ and $R_{m,fast}$ are the total and fast reserve amounts for the optimum solution for that hour as a result of first stage.

In the second stage, final check is performed in case there exists a solution which is more optimum than the existing solution. Procedure for final check is given in Figure 3.19.

Firstly, it is checked whether Stage 2 is activated before or not. If it is the first time for Stage 2, the amount of fast reserve resulted from Stage 1 is increased by 25 MW. If it is not, fast reserve amount of the previous trial is increased by 25 MW. Reserve constraint for total amount of reserve chosen to be 0 for both cases.

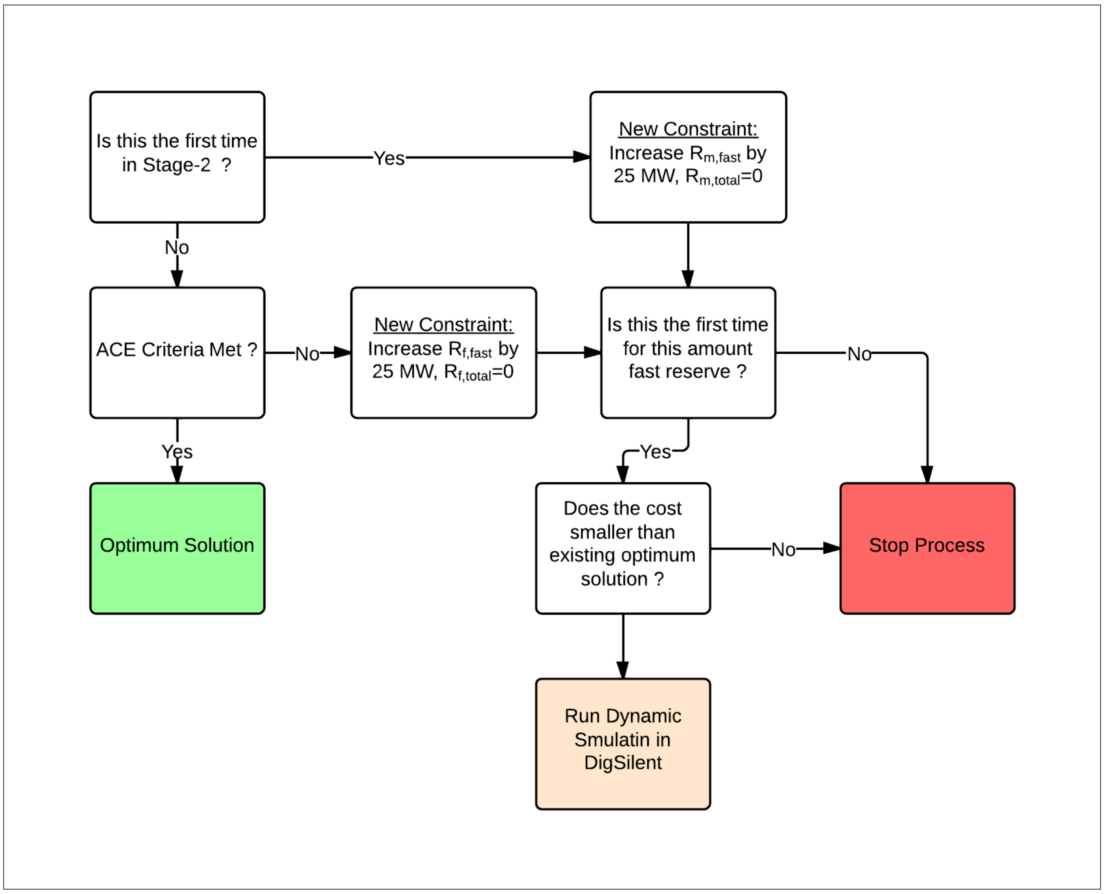


Figure 3.19 Assessment of ACE, Stage 2

Then it is checked whether the new trial of reserve amount is tried before in Stage 1. If it is, process is stopped. If it is not, cost of new commitment is checked via utilizing MILPROG. If it less costly than the existing solution, DigSilent simulation is done in order to assess the ACE performance of the new trial, process is stopped otherwise.

CHAPTER 4

SIMULATIONS AND RESULTS

4.1. Preparation of Load Disturbance Scenarios

The main purpose of the AGC system is to hold the frequency at its nominal value besides maintaining the power exchange through tie lines at the scheduled value as mentioned in the previous chapters. In order to test the developed algorithm mentioned in Chapter 3, test data is required for simulations. For this purpose demand of EAFs are chosen to represent the rapid load variations in the system.

The steel industry is the main source of the rapid variations of the load causing undesired power flows on tie lines [9]. This is due to the stochastic behavior of the electric arc furnaces around a mean operating level [14]. Structure of an EAF is shown in Figure 4.1 below.

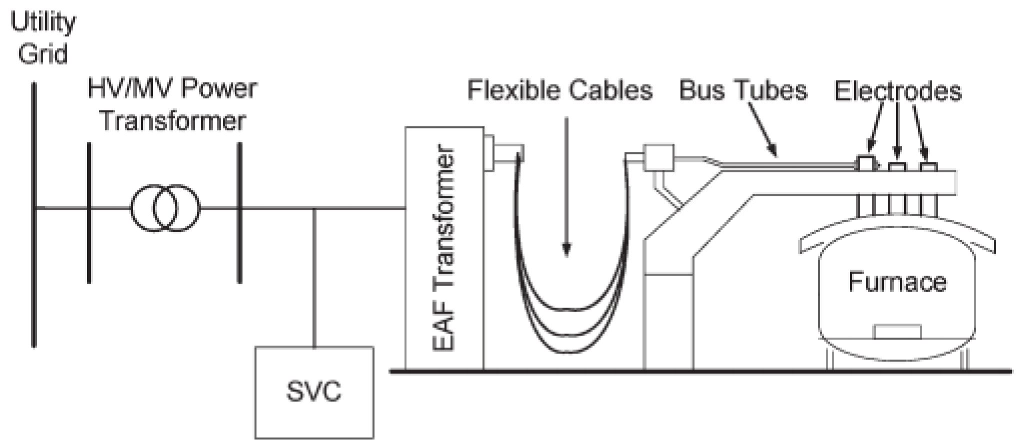


Figure 4.1 EAF Power System [15]

Power system of an EAF consists of an SVC, a transformer, flexible cables, bus tubes and electrodes. Cable, bus tubes and electrodes constitute the 75 % of the impedance seen from the low voltage side of the EAF transformer. Operation of an EAF has three main stages, namely; boring, melting and refining. Active power demand of EAF changes randomly especially in the scrap melting phase. Moreover, changing the tap position of the EAF continually during the operation reflects the varying arc resistance to primary side that results a further change in active power demand [15].

PMU measurements are available for several EAFs in the system. List of EAFs used throughout the simulation studies is presented in Table 4.1 below. Normal load represents the non-varying part of the consumption where the impact load corresponds to the rapidly varying part of the total active power demand of the related EAF.

In order to understand the size of the steel industry in Turkey, list of EAFs with significant consumption in Turkish grid and their active power demands are shown in Table 4.2.

Table 4.1 Active Power Demand of EAFs

EAF Name	Normal Load (MW)	Impact Load (MW)
EAF 1	119	410
EAF 2	480	175
EAF 3	40	155
EAF 4	19	135
EAF 5	40	134
EAF 6	30	105
EAF 7	0	90
EAF 8	160	50
EAF 9	10	20

Table 4.2 EAFs with Significant Consumption

EAF Name	Normal Load (MW)	Impact Load (MW)
T-EAF 1	119	410
T-EAF 2	55	277
T-EAF 3	100	178
T-EAF 4	480	175
T-EAF 5	40	155
T-EAF 6	50	150
T-EAF 7	19	135
T-EAF 8	40	134
T-EAF 9	30	120
T-EAF 10	30	105
T-EAF 11	0	90
T-EAF 12	40	90
T-EAF 13	0	72
T-EAF 14	15	70
T-EAF 15	16	64
T-EAF 16	60	58
T-EAF 17	25	56
T-EAF 18	160	50
T-EAF 19	12	48
T-EAF 20	12	45
T-EAF 21	10	40
T-EAF 22	10	35
T-EAF 23	10	33
T-EAF 24	10	20

When load demand characteristics of arc furnaces are investigated, it can be clearly observed that their demand changes cyclically. In Figure 4.2 below, load demand characteristic of EAF 7 is shown for a 4 hour duration. From the figure it is understood that EAF 7 has a cyclic operation of about 45 minutes. In Figure 4.3, a different demand characteristic of an arc furnace is presented. EAF 9 has an oscillatory demand when arc furnace is in operation.

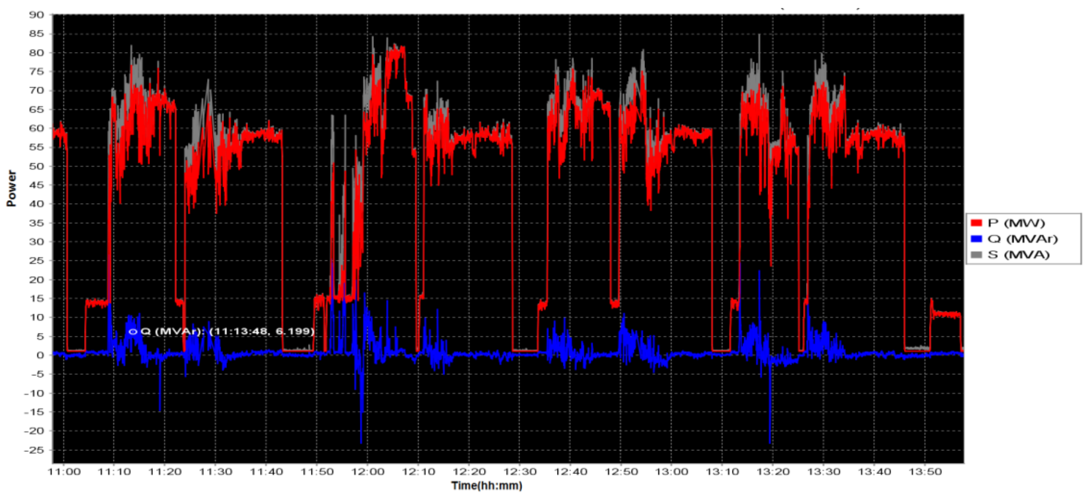


Figure 4.2 Demand Characteristic of EAF 7

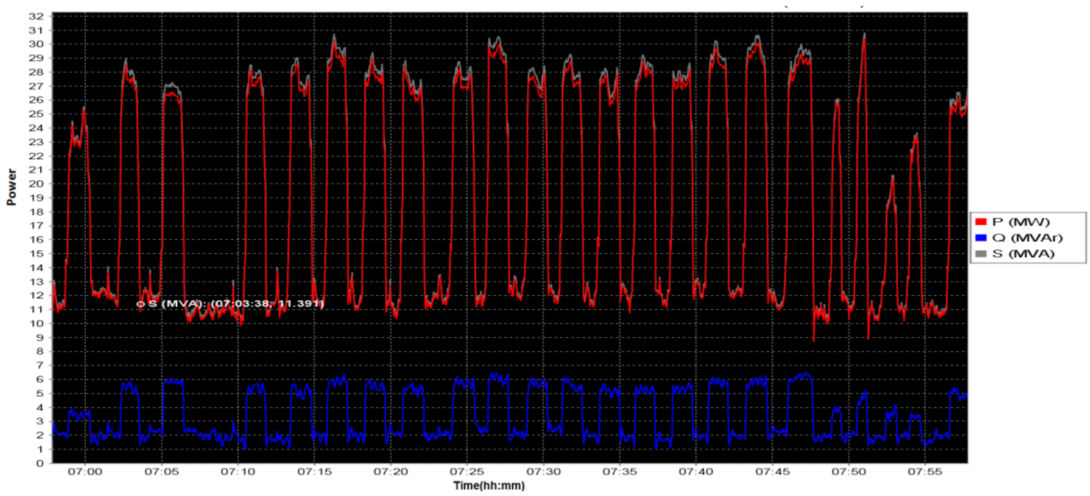


Figure 4.3 Demand Characteristic of EAF 9

Therefore while creating a reasonable set of disturbance data for simulation studies, real measurements from PMU system are obtained on an hourly basis with 3 seconds averages, and the moment for an arc furnace to start operation in the intra-hour has been chosen randomly. A typical load characteristic of EAFs during a sample day from July 2014 is shown in Figure 4.4. Data are formed using 10 sec average values obtained from SCADA. In Appendix B, typical load demands of EAFs for a few hours are presented.

Optimal determination and allocation of secondary frequency control reserve algorithm is tested and results are presented for three cases. These three cases differ from each other by the level of power demand of the EAFs in operation. In the assessment on AGC performance, "% of abs(ACE) >100 MW" for 15 minute observation period are not tabulated since this criterion is not violated in any iteration in any case.

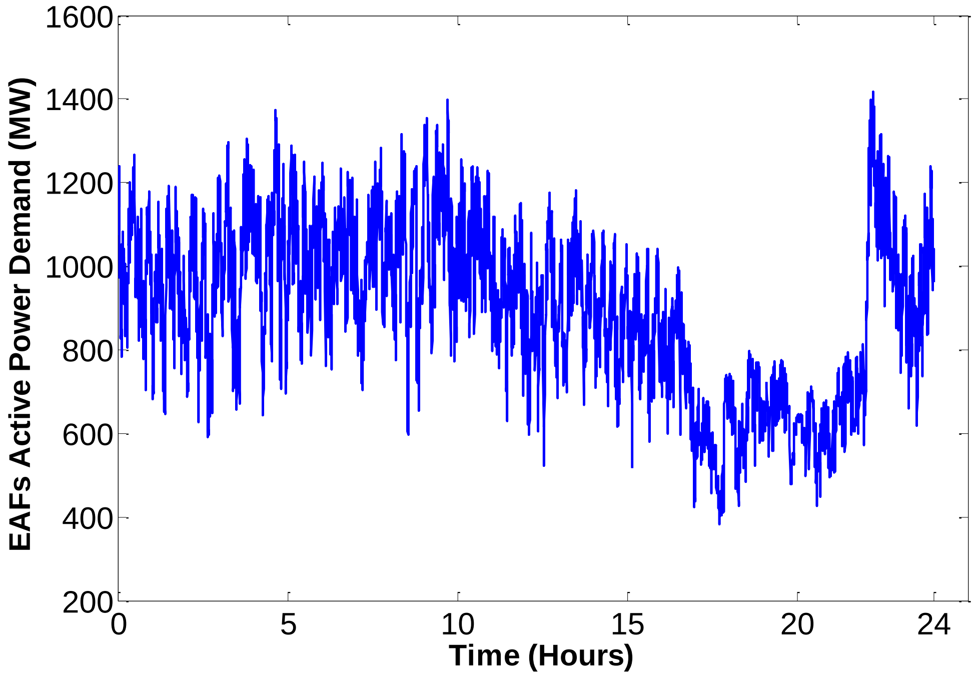


Figure 4.4 Typical Load Profile of EAFs

4.2. Case 1: Low Level of Arc Furnace Demand

In this case, low level of EAF demand, i.e., demand is below daily average value, is utilized in order to test the developed algorithm. Load disturbance test data are generated by using the demand characteristics of EAFs given in Table 4.1. EAFs in operation are selected randomly and corresponding total active power demand is shown in Figure 4.5. Standard deviation of the disturbance data, σ, is calculated to be 129.15 MW and maximum rate of change in load is 97 MW/seconds. YAL and YAT bids of the GENCOs for that case are taken from TEAİŞ for a specific hour formerly realized in day-ahead market. Corresponding bids are presented in Table 4.3 below. Name of the GENCOs are not given since bids are considered as confidential information.

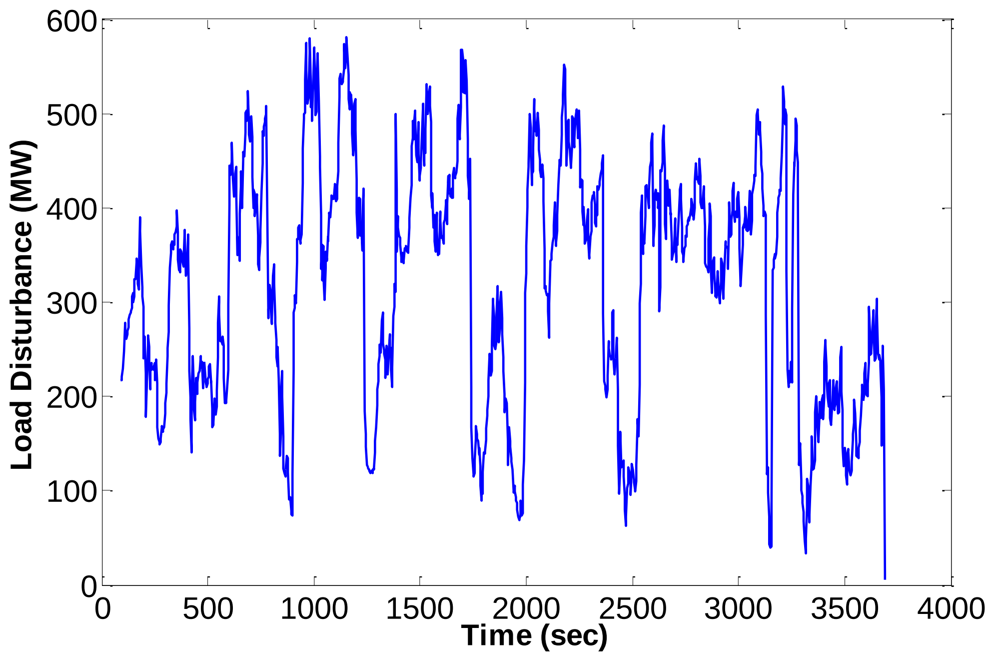


Figure 4.5 Load Disturbance Test Data for Case 1

Table 4.3 YAL and YAT Bids of GENCOs for Case 1

Name	Availability	Avg. YAL (MW/TL)	Avg. YAT (MW/TL)	Max Reserve (MW)	Required Order (MW)
PP1	1	204.03	12	100	100
PP2	1	204.02	11.99	80	0
PP3	0	213.02	0	0	0
PP4	0	213.31	4.49	10	0
PP5	1	220	14.02	40	40
PP6	1	235	0	38.5	38.5
PP7	1	235	0	38.5	38.5
PP8	1	235	0	38.5	38.5
PP9	0	235	0	34.5	34.5
PP10	1	235	0	38.5	38.5
PP11	1	235	0	38.5	38.5
PP12	1	192	22	177	177
PP13	1	0	139.99	0	0
PP14	1	245	0	24	24
PP15	1	246	0	24.5	24.5
PP16	1	0	40	18.5	-18.5
PP17	1	0	40	18.5	-18.5
PP18	1	0	40	18.5	-18.5
PP19	0	0	25	30	-24
PP20	0	202.01	11.19	0	0
PP21	1	0	21	22	-22
PP22	1	145	20	24	-24
PP23	1	349.97	0	32	104
PP24	0	180.86	139.99	0	0
PP25	1	230	0	31	31
PP26	1	0	13	33.5	-33.5
PP27	1	250	0	0	0
PP28	1	0	20	38	-38

Allocation of reserve groups for each iteration is given in Appendix C.

Initial guess for Iteration 1 is decided as 600 MW. After simulating the corresponding commitment, which is an output of the MILPROG utilized in

MATLAB, total flows on tie lines and utilization of reserve groups are presented in Figure 4.6 and Figure 4.7 respectively.

AGC performance criteria, “% of abs(ACE)>175 MW” and “% of abs(ACE)>100 MW” are calculated to be 11.11% and 32.56%, respectively for Iteration 1. Since second criterion is not satisfactory, further iteration with 650 MW of total reserve constraint is utilized.

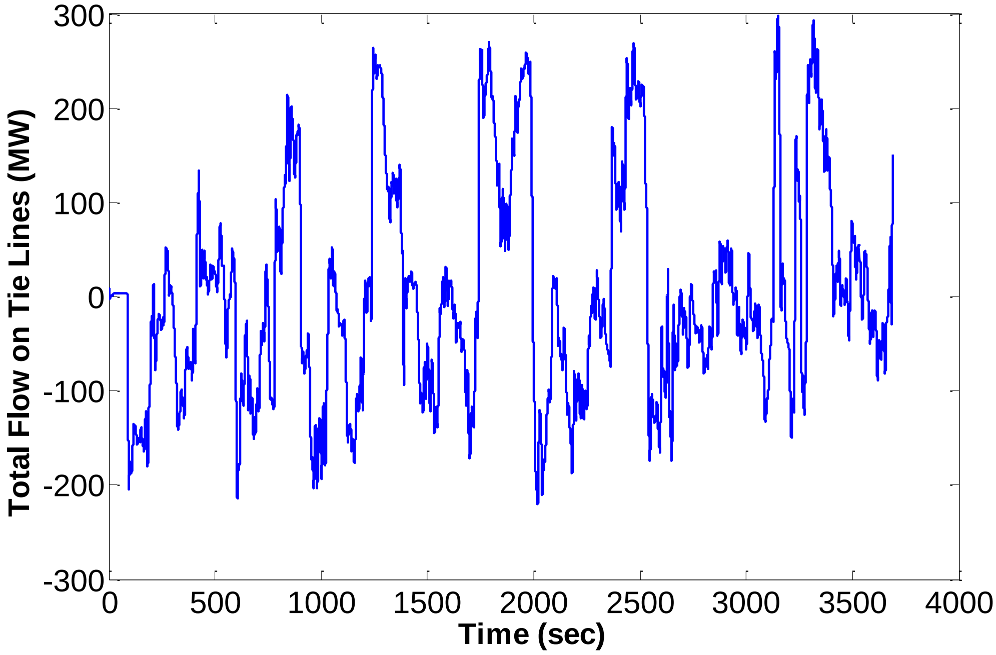


Figure 4.6 Case 1:Total Tie Line Flow in Iteration 1

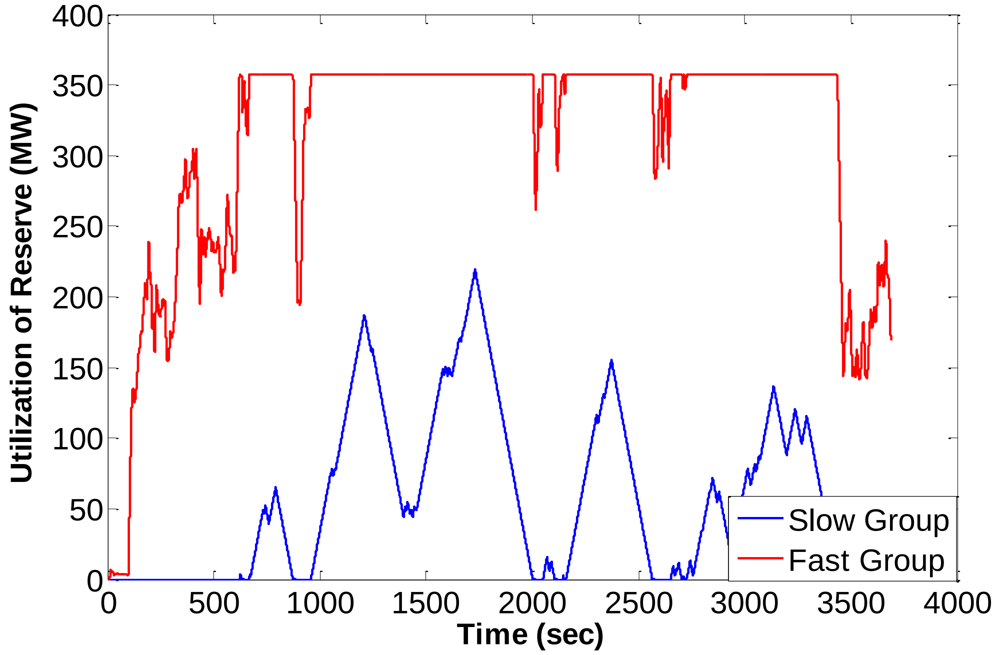


Figure 4.7 Case 1: Utilization of Reserve Groups in Iteration 1

After dynamic simulation is conducted in DigSilent, Figure 4.8 and Figure 4.9 are obtained for the tie line flows and utilization of reserve groups, respectively. Percentage errors for this case are calculated as 10.22% and 31.33% for "% of abs(ACE)>175 MW" and "% of abs(ACE)>100 MW", respectively. This result is satisfactory however an alternative option with less cost may exist. Therefore as the flow chart implies, amount of total reserve is decreased by 25 MW.

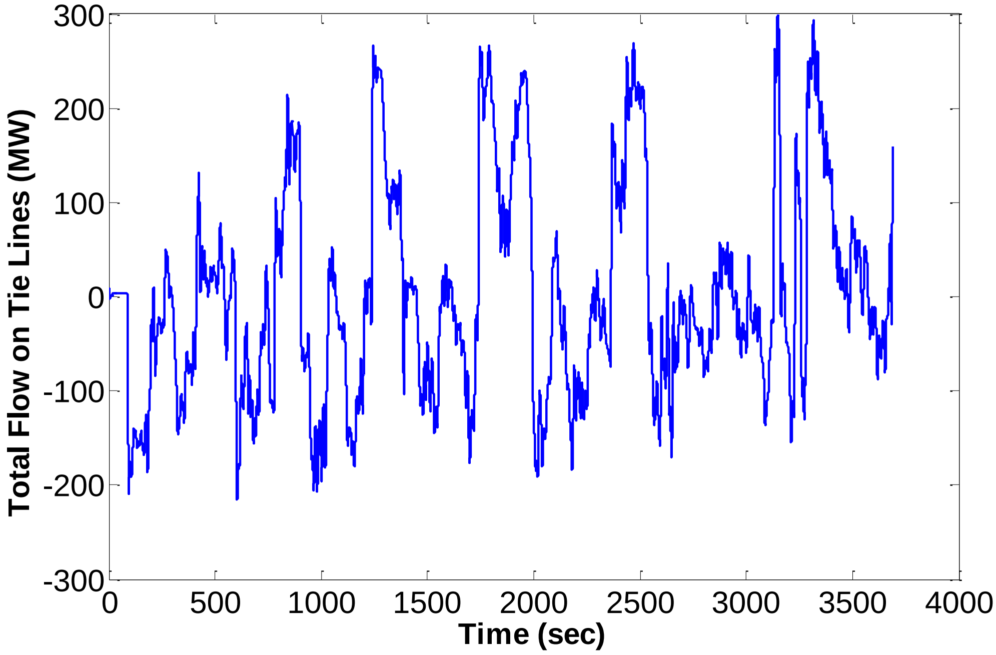


Figure 4.8 Case 1:Total Tie Line Flow in Iteration 2

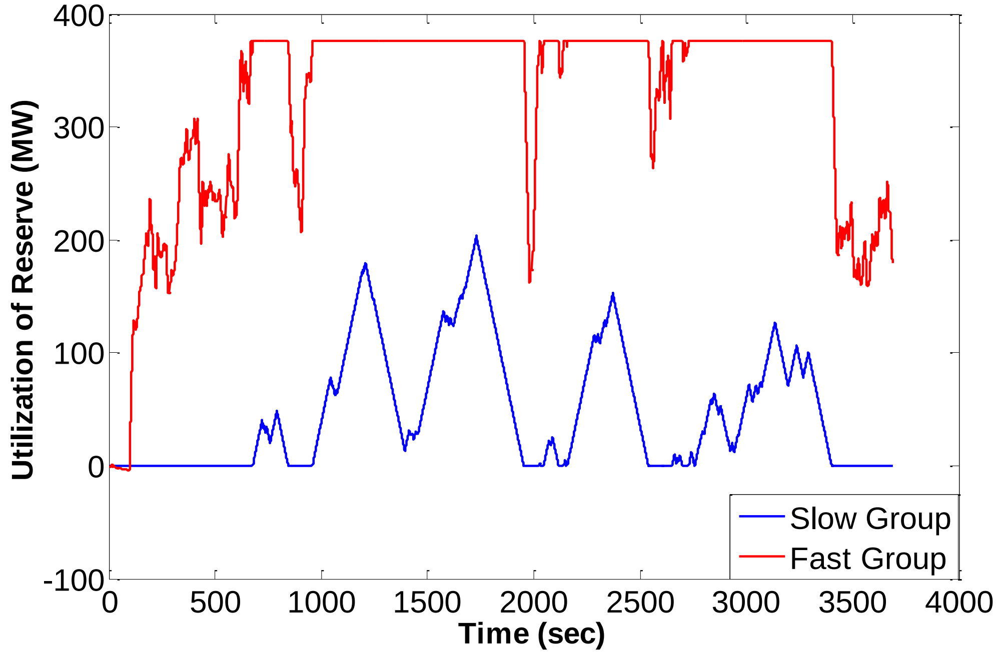


Figure 4.9 Case 1: Utilization of Reserve Groups in Iteration 2

After utilizing the new reserve constraint, total amount of 625 MW of secondary reserve is constituted with 366 MW for fast reserve group. Dynamic simulation results for Iteration 3 are presented in Figure 4.10 and Figure 4.11 for tie line flows and utilization of secondary reserve, respectively.

AGC performance criteria for this case are 11% and 31.67% for % of abs(ACE)>175 MW and % of abs(ACE)>100 MW. Therefore commitment in the previous iteration, i.e., Iteration 2, is the optimum existing solution. However, another consideration by applying a fast reserve constraint is required. Therefore fast reserve constraint with 25 MW of increment, 401 MW, is applied in MILPROG. Resultant dispatch comes out to be 492 MW for total reserve and 401 MW for fast group allocation.

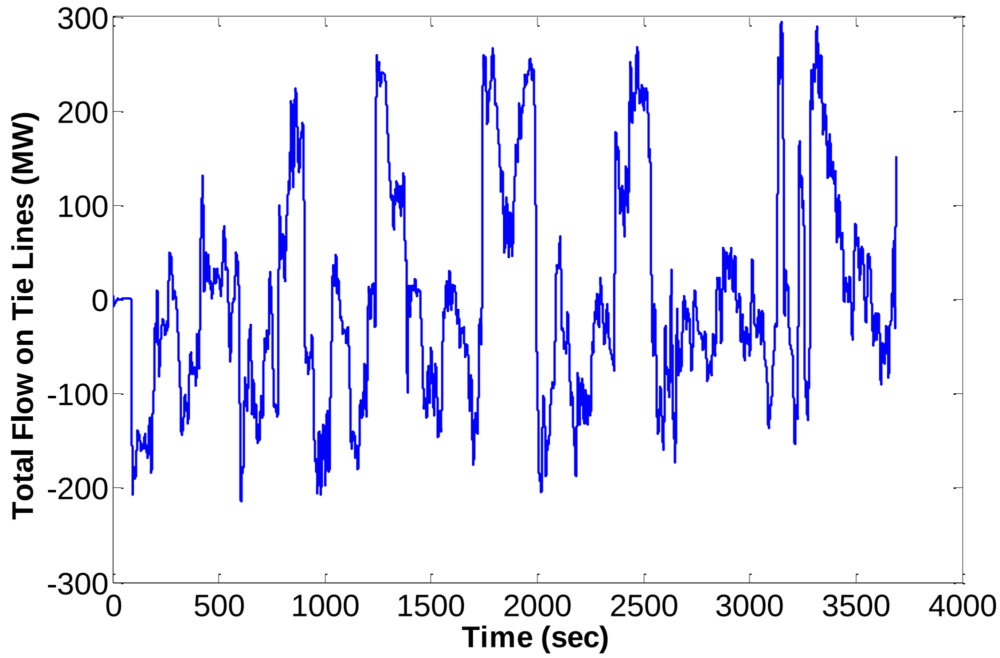


Figure 4.10 Case 1: Total Tie Line Flow in Iteration 3

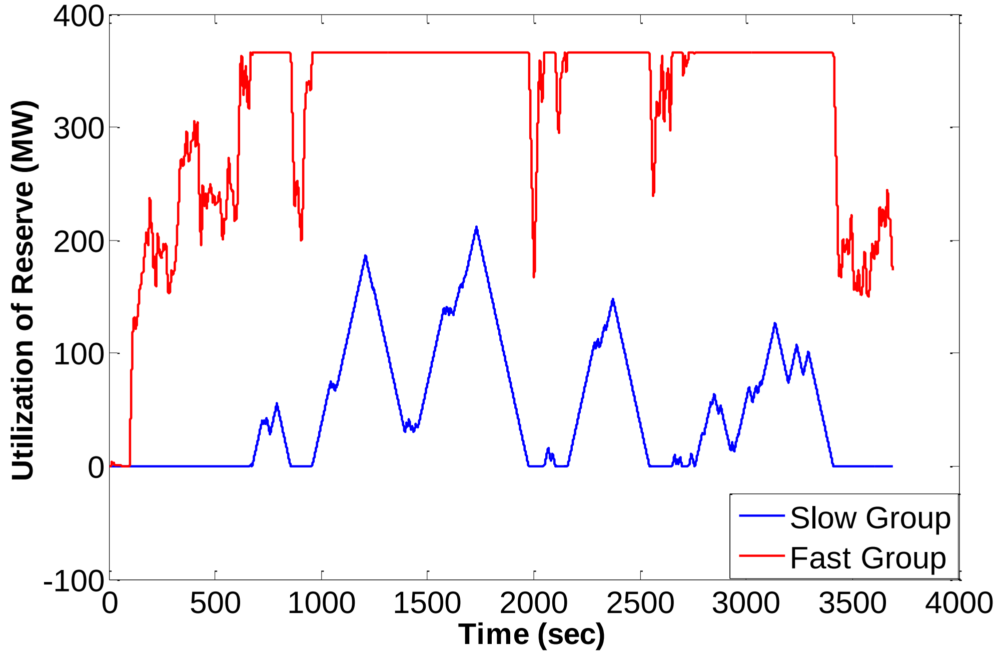


Figure 4.11 Case 1: Utilization of Reserve Groups in Iteration 3

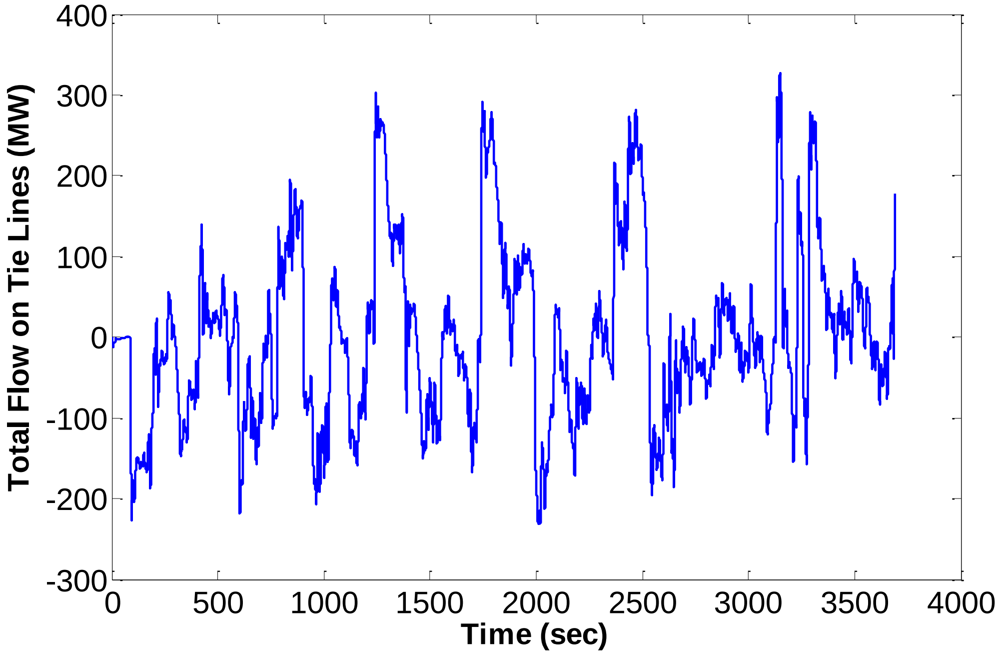


Figure 4.12 Case 1:Total Tie Line Flow in Iteration 4

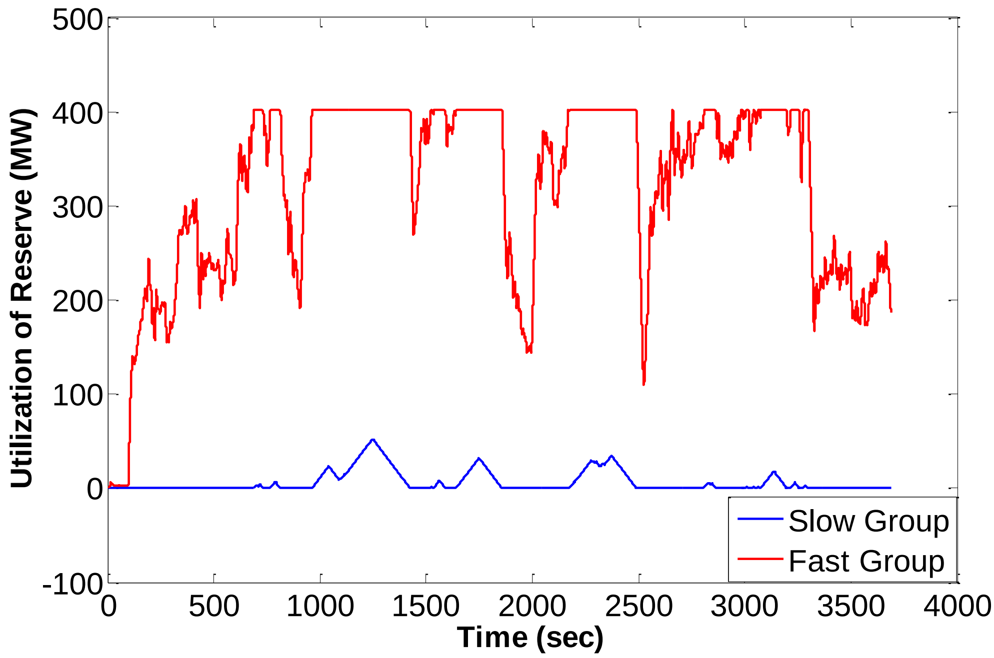


Figure 4.13 Case 1: Utilization of Reserve Groups in Iteration 4

Dynamic simulation results of Iteration 4 are given in Figure 4.12 and Figure 4.13. Corresponding ACE for this iteration are within acceptable limits with less cost than the Iteration 2. Therefore, commitment of Iteration 4 is the optimum solution that the algorithm provides. Summary of the results regarding Case 1 is given in Table 4.4 below.

Table 4.4 Summary of Case 1

Iteration No	Total Reserve (MW)	Fast Reserve (MW)	% of abs(ACE)>175 MW	% of abs(ACE)>100 MW	Cost (TL)
1	600	357	11.11	32.56	65,811
2	650	376	10.22	31.33	77,561
3	625	366	11.00	31.67	71,686
4	490	401	9.39	27.78	46,532

4.3. Case 2: Moderate Level of Arc Furnace Demand

The data used for creating load disturbance data consist of the combination of PMU measurements of listed EAFs in Table 4.1. Measurements obtained are 3 second average demand values of the arc furnaces. Load disturbance data are prepared for 1 hour and starting point of each arc-furnace operation is chosen randomly within the hour, i.e., arc furnaces do not start to operate simultaneously. In Figure 4.14 below, corresponding load disturbance data are presented. Standard deviation of load data is σ= 153.707 MW and the maximum rate of change in load is 114 MW/seconds. Besides, bids of the GENCOs for YAL and YAT orders are given in Table 4.5.

For the first iteration, total reserve amount is guessed to be 800 MW. As a result of the cost optimization algorithm, 409 MW of it is allocated for fast group of reserve. With load disturbance data included, the case for that hour is simulated via DigSilent. Corresponding total power flow via interconnection lines is shown in Figure 4.15. Amount of allocation of fast and slow reserve groups are presented in Figure 4.16. "% of abs(ACE)>175 MW" for this iteration is calculated to be 8.28% which is below 11. In addition to that, "% of abs(ACE)>100 MW "is below 33%. Since Iteration 1 satisfies ACE criteria, in Iteration 2, cheaper alternative of reserve constitution is aimed. As stated in the previous chapter, next step is to decrease total reserve amount by 50 MW without any fast reserve constraint since slow group of reserve is also activated in first iteration.

Table 4.5 YAL and YAT Bids of GENCOs for Case 2

Name	Availability	Avg YAL (MW/TL)	Avg YAT (MW/TL)	Max Reserve (MW)	Required Order (MW)
PP1	1	204.05	12	60	0
PP2	1	204.03	11.99	60	0
PP3	0	213.02	0	0	0
PP4	0	213.31	4.49	10	0
PP5	1	0	12.02	40	-40
PP6	1	235	0	39	39
PP7	1	235	0	39	39
PP8	1	235	0	39	39
PP9	0	235	0	36	36
PP10	1	235	0	39	39
PP11	1	235	0	39	39
PP12	1	0	22	177	-177
PP13	1	0	139.99	0	0
PP14	1	599	0	0	117
PP15	1	599	0	0	121
PP16	1	0	40	18.5	-18.5
PP17	1	0	40	18.5	-18.5
PP18	1	0	40	18.5	-18.5
PP19	0	0	25	30	-24
PP20	0	202.01	11.19	0	0
PP21	1	0	21	23	-23
PP22	1	145	20	24	-24
PP23	1	349.97	0	32	104
PP24	0	180.86	139.99	0	0
PP25	1	230	0	31	31
PP26	1	0	13	33.5	-33.5
PP27	1	250	0	0	0
PP28	1	0	20	38	-38

Allocation of reserve groups for each iteration is given in Appendix C.

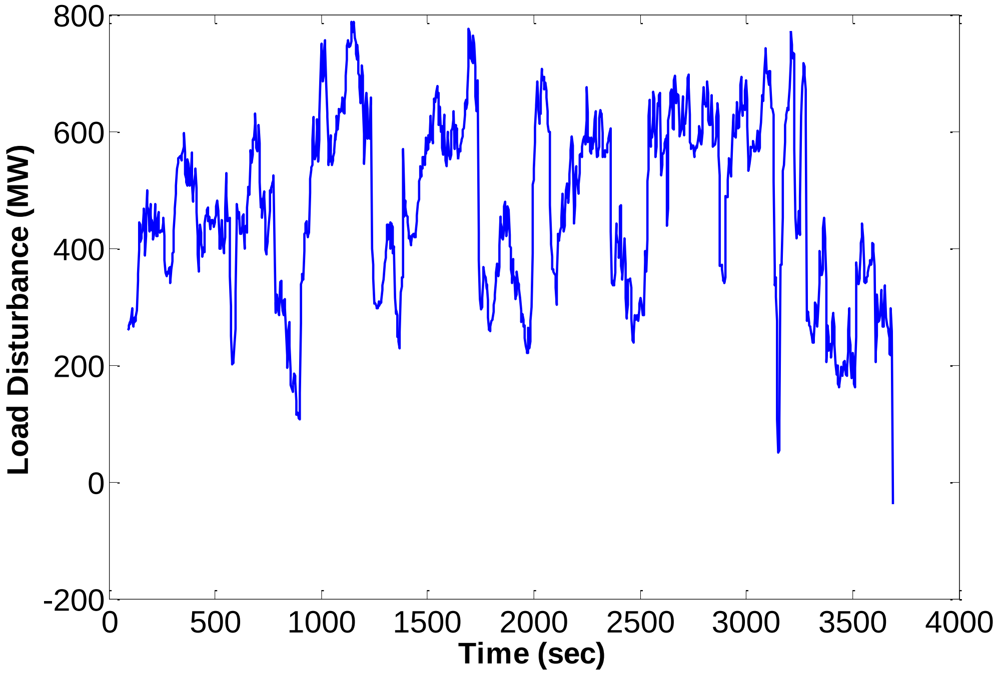


Figure 4.14 Load Disturbance Test Data for Case 2

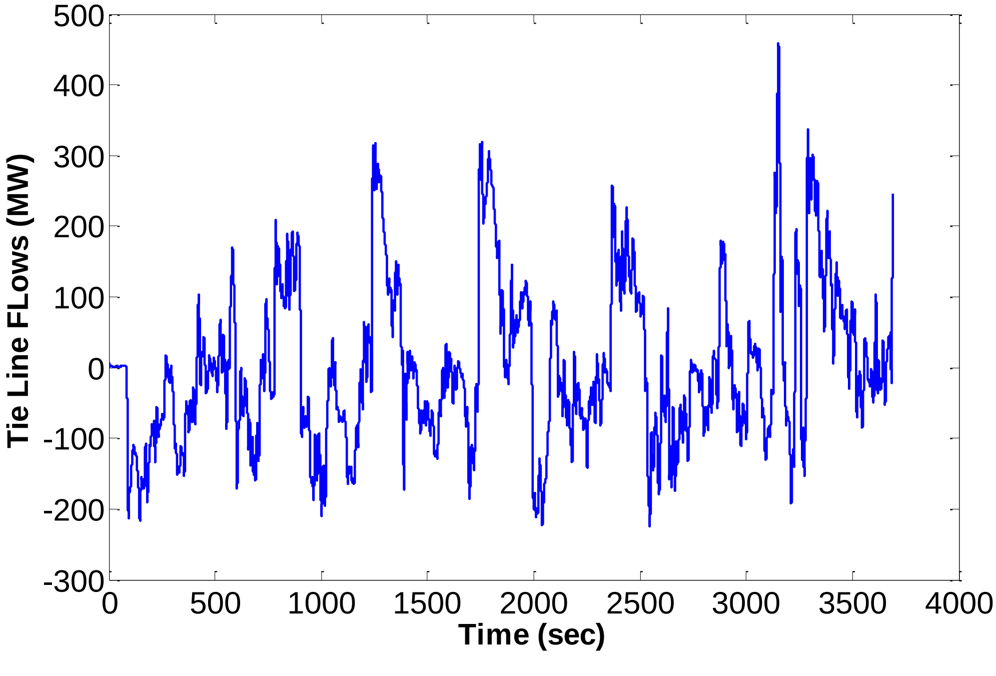


Figure 4.15 Case 2: Total Tie Line Flow in Iteration 1

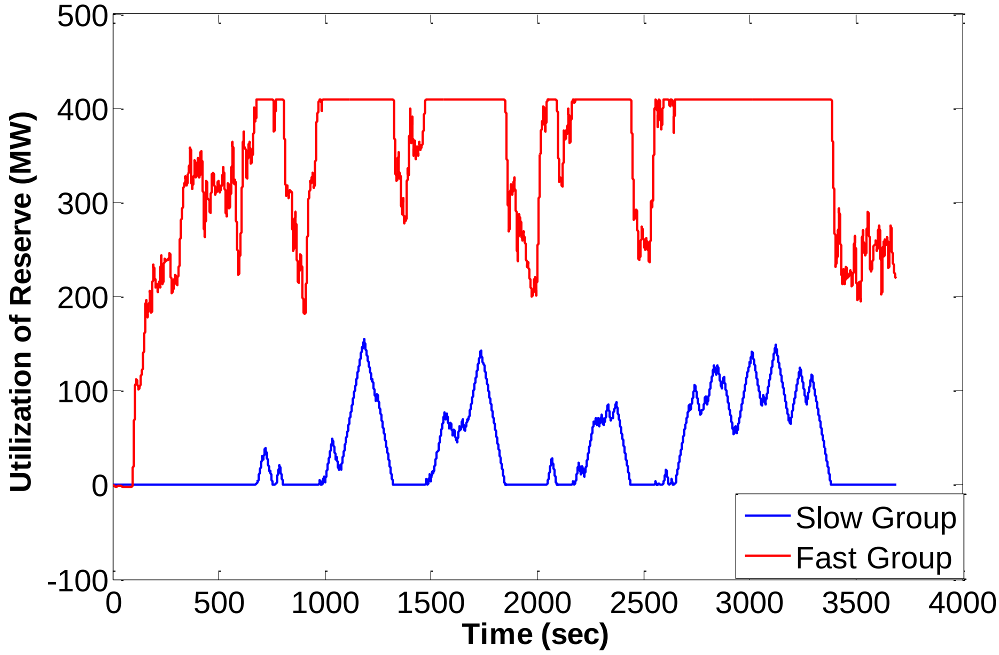


Figure 4.16 Case 2:Utilization of Reserve Groups in Iteration 1

As a result of cost optimization algorithm for Iteration 2, total amount of 750MW reserve with 364MW allocated for fast group is committed. Then dynamic simulation is performed. Following figures, Figure 4.17 and Figure 4.18, show total power exchange on tie lines and reserve used from fast and slow groups respectively.

In the assessment of AGC performance "% of abs(ACE)> 175 MW" for Iteration 2 is 10.11% and "% of abs(ACE)> 100 MW" is 35.22%. One of the ACE criteria is not satisfied for Iteration 2. Therefore, in the next iteration, Iteration 3, total reserve constraint will be increased by 25 MW as the flow chart implies. Commitment of 775 MW of total reserve with 391 MW allocated for fast group is utilized in Iteration 3.

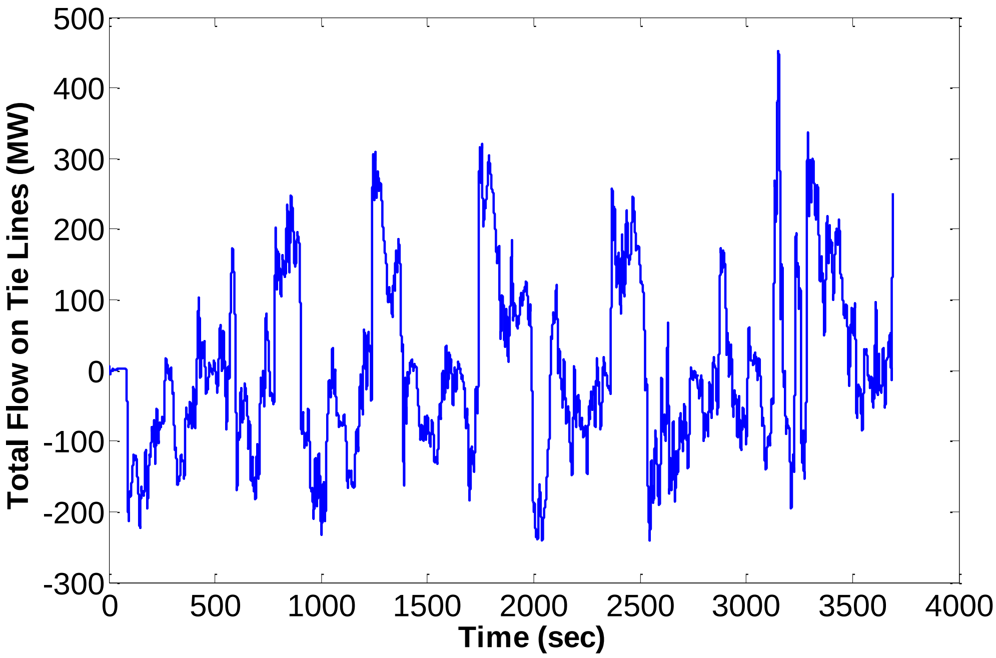


Figure 4.17 Case 2:Total Tie Line Flow in Iteration 2

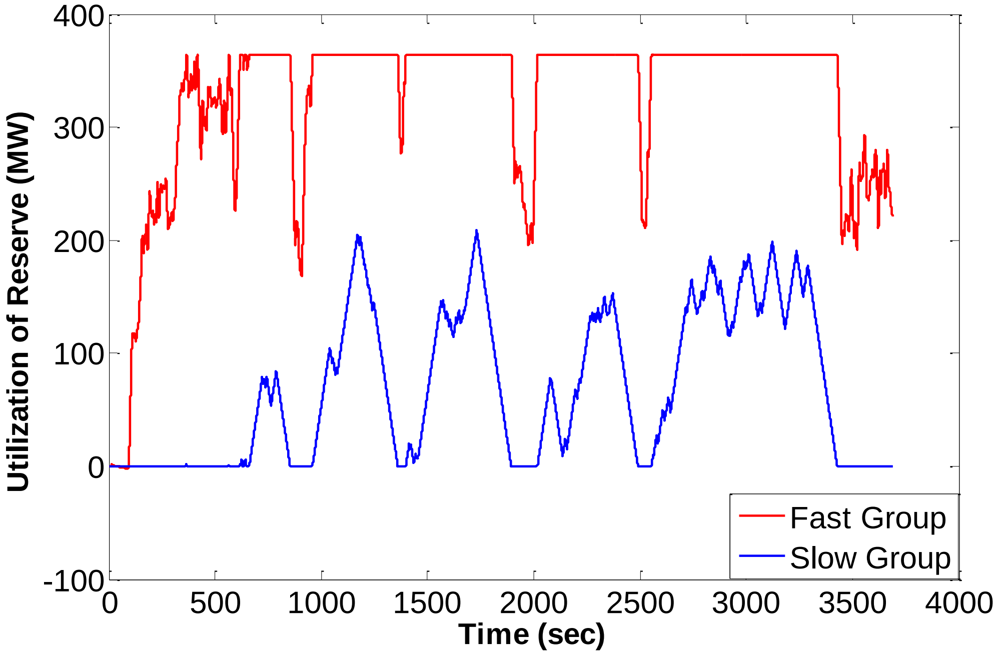


Figure 4.18 Case 2:Utilization of Reserve in Iteration 2

After simulating the dynamic model for Iteration 3, total flows on tie lines and utilization of the reserve groups are presented in Figure 4.19 and Figure 4.20, respectively. Following the dynamic simulation, "% of abs(ACE)>175 MW" and " % of abs(ACE)>100 MW" are calculated and corresponding values 8.39% and 30.89% are found, respectively. Next iteration requires a reserve provision with 787.5 MW total reserve constraint. However, difference in power dispatch between the existing and proposed solution is not greater than 25 MW. Therefore, next iteration, as explained in Chapter 3, aims to increase the amount of fast responsive reserve group while decreasing the total amount of reserve. In order to achieve it, cost optimization algorithm for selection of reserve group is utilized with a fast group reserve constraint which is 25 MW higher than the fast group reserve of the existing optimum solution. As a result of cost optimization algorithm, reserve support of 391 MW in fast group is more expensive than the existing solution obtained in Iteration 3. Therefore there is no need for a dynamic simulation for Iteration 4. Allocation of reserve for fast and slow groups in Iteration 3 is the solution with minimum cost for Case 2 that the algorithm provides.

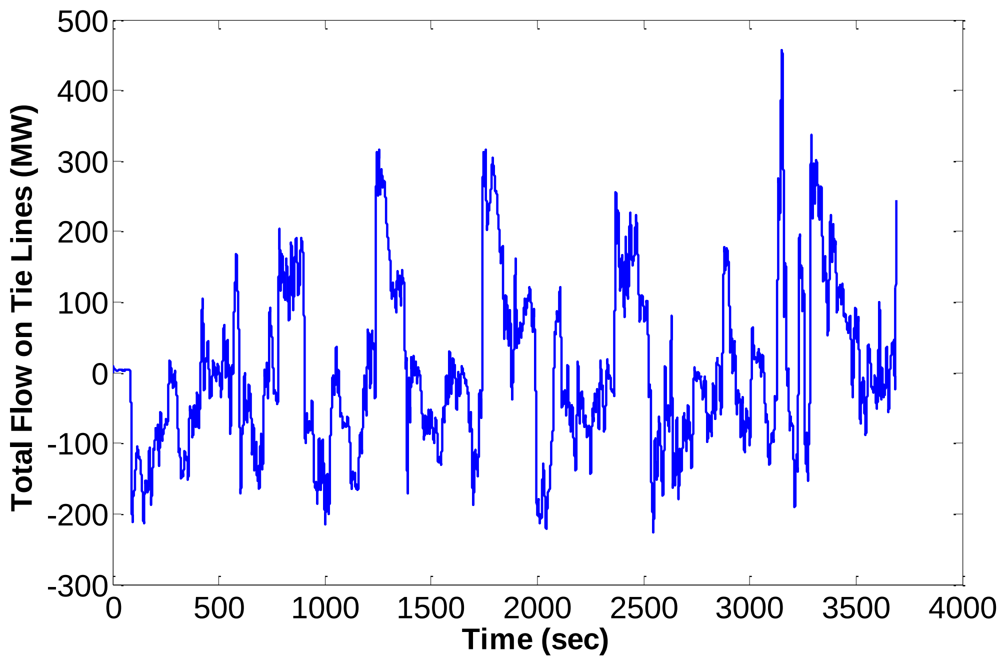


Figure 4.19 Case 2:Total Tie Line Flow in Iteration 3

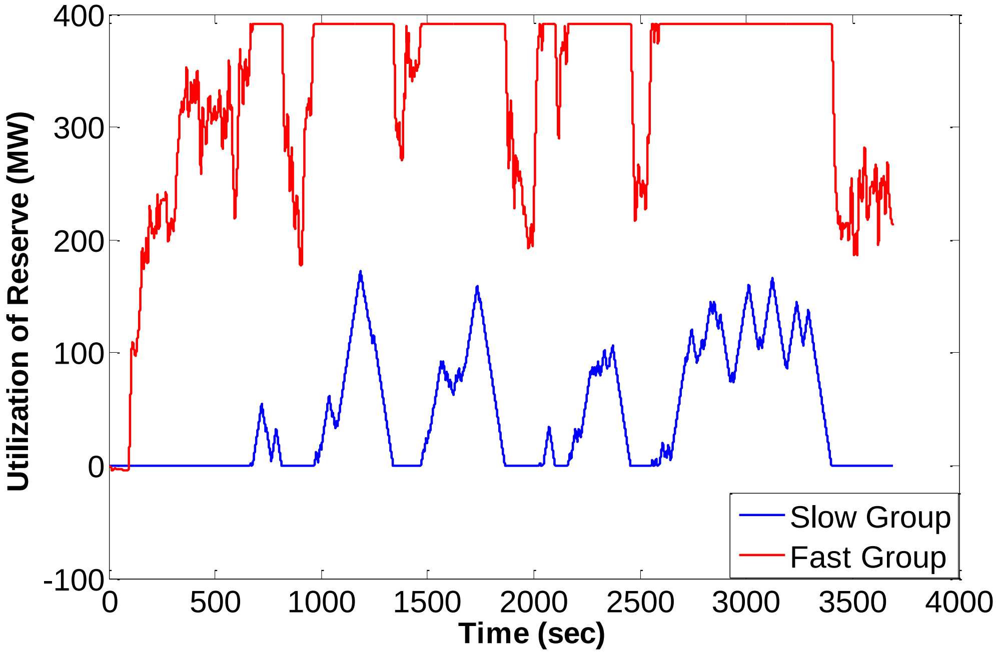


Figure 4.20 Case 2: Utilization of Reserve Groups in Iteriation 3

In Table 4.6 summary of the iteration process is given.

Table 4.6 Summary of Case 2

Iteration No	Total Reserve (MW)	Fast Reserve (MW)	% of abs(ACE)>175 MW	% of abs(ACE)>100 MW	Cost (TL)
1	800	409	8.28	29.83	127,780
2	750	364	10.11	35.22	76,776
3	775	391	8.39	30.89	93,031
4	651	416	No Simulation Necessary	No Simulation Necessary	103,440

4.4. Case 3: High Level of Arc Furnace Demand

In this case, developed algorithm has been executed in an operating condition with a high level of arc furnace demand, i.e., demand is greater than the daily average value. YAL and YAT bids of the GENCOs for the corresponding hour are presented in Table 4.7. Bids used in simulations reflect the actual prices from a specific hour of the day-ahead market and obtained from TEİAŞ.

Table 4.7 YAL and YAT Bids of GENCOs for Case 3

Name	Availability	Avg. YAL (MW/TL)	Avg. YAT (MW/TL)	Max Reserve (MW)	Required Order (MW)
PP1	1	204.03	12	80	-80
PP2	1	204	11.99	100	-100
PP3	0	213.02	0	0	0
PP4	0	213.31	4.49	5	0
PP5	1	220	14.02	40	-40
PP6	1	235	0	37.5	37.5
PP7	1	235	0	37	37
PP8	1	235	0	37	37
PP9	0	235	0	38	37
PP10	1	235	0	38	38
PP11	1	235	0	38,5	38.5
PP12	1	0	42	169	-169
PP13	1	0	21	78.5	-78.5
PP14	1	0	15	24	-24
PP15	1	0	15	27	-27
PP16	1	0	40	18.5	-18.5
PP17	1	0	40	18.5	-18.5
PP18	1	0	40	18.5	-18.5
PP19	0	0	25	30	-24
PP20	0	202.01	11.19	0	0
PP21	1	0	41	21	-21
PP22	1	192.43	20	24	-24
PP23	1	0	65	32	-32
PP24	0	192.43	5	0	0
PP25	1	192.43	20	31	-31
PP26	1	0	13	33.5	-33.5
PP27	1	250	20	10	-10
PP28	1	0	20	38	-38

Inital amount of the reserve is guessed to be 900 MW for this case. Therefore; MILPROG is executed with 900 MW total reserve constraint. Resultant commitment consists of 483 and 487 MW of reserves for fast and slow groups, respectively. Allocation of reserve groups for each iteration are given in Appendix C.

Load disturbance test data that is applied to system is given in Figure 4.21. Standard deviation for load disturbance is 191 MW and maximum rate of change in demand is 99 MW/second.

After simulating the dynamic model of Turkish HV network with the ENTSO-E system equivaelnt in DigSilent, corresponding flows on tie lines and utilization of reserve groups for Iteration 1 are presented in Figure 4.22 and Figure 4.23, respectively.

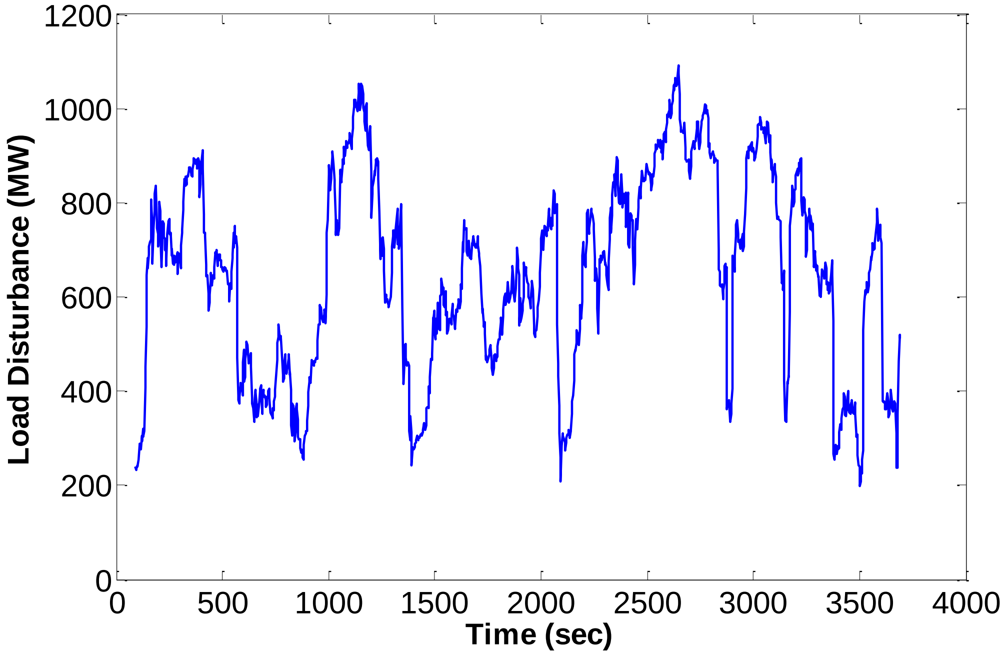


Figure 4.21 Load Disturbance Test Data for Case 3

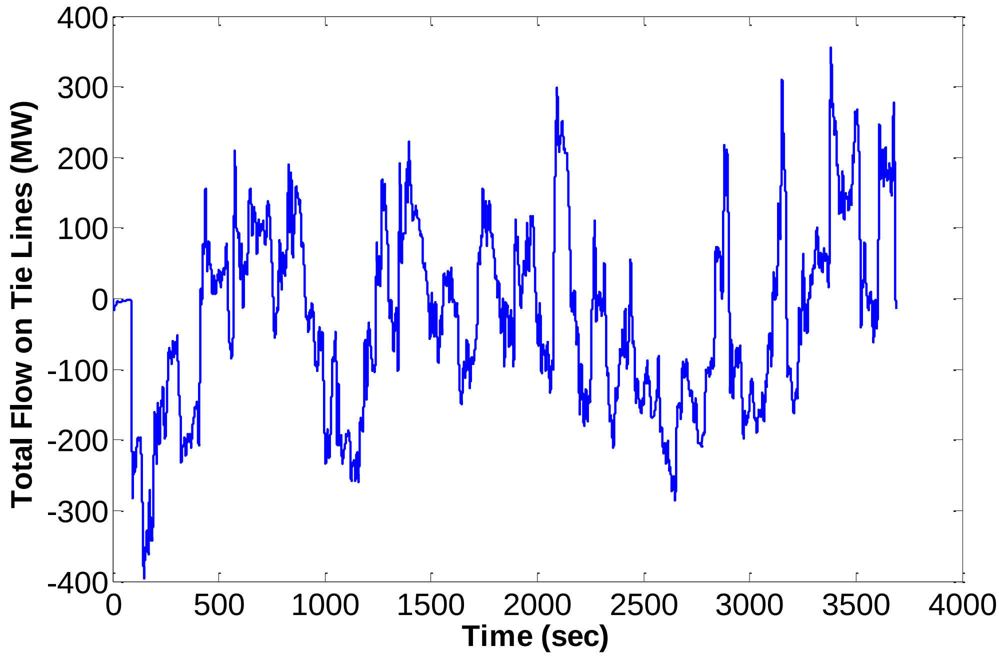


Figure 4.22 Case 3:Total Tie Line Flow in Iteration 1

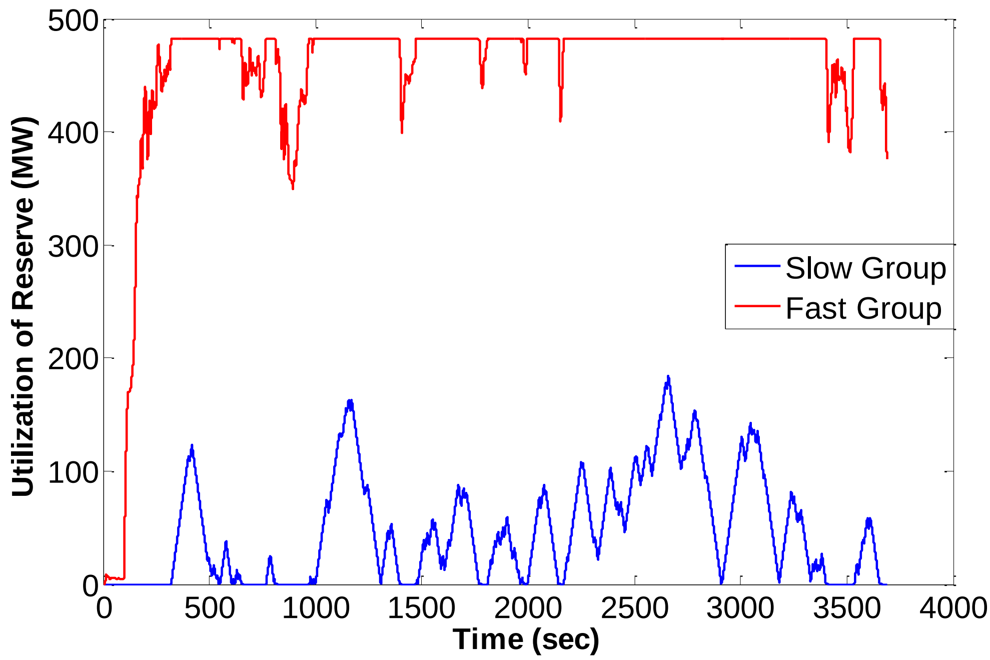


Figure 4.23 Case 3: Utilization of Reserve Groups in Iteriation 1

According to total flow on tie lines, “% of abs(ACE)>175 MW” is calculated to be % 12.61, whereas “% of abs(ACE)>100 MW” is 40.61%. ACE criteria are not satisfactory, so further iteration is required. Total amount of reserve is increased by 50 MW as the flow chart implies for the next iteration.

In order to commit power plants according to the new reserve constraint, 950 MW, MILPROG is utilized. Resultant commitment is transferred to DigSilent environment by the developed DPL (DigSilent Programming Language).

Total tie line flows and utilization of reserve groups are presented in Figure 4.24 and Figure 4.25, respectively as a result of Iteration 2. AGC performance critera, “% of abs(ACE)>175 MW” and “% of abs(ACE)>100 MW” are calculated to be 10.72% and 38.56% respectively. Since the second criterion is not satisfied, results of Iteration 2 are not satisfactory from ENTSO-E point of view. Therefore, a new iteration with increased amount of reserve is required.

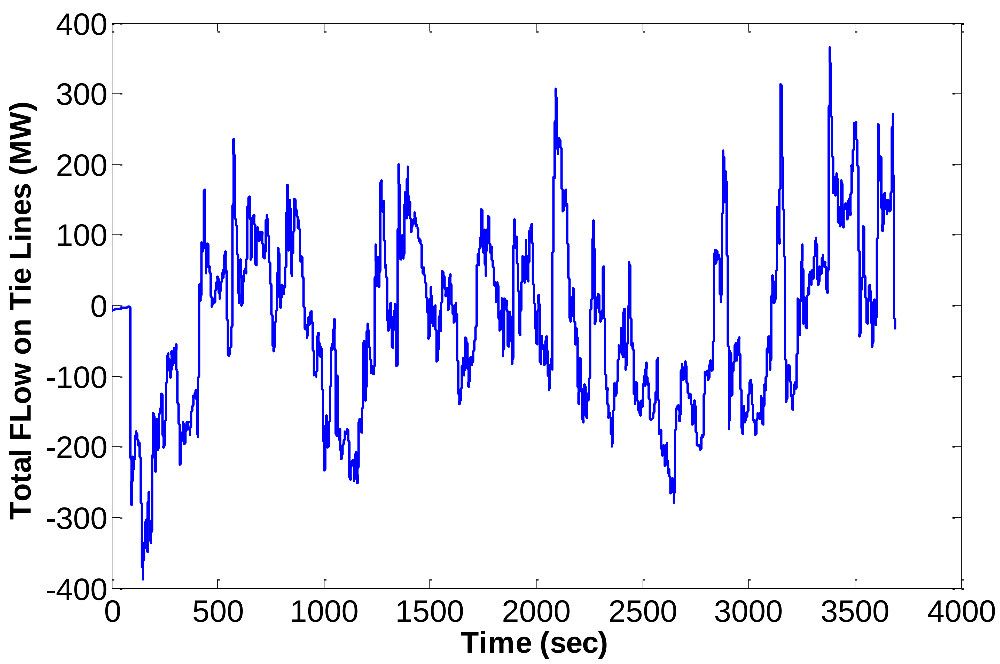


Figure 4.24 Case 3:Total Tie Line Flow in Iteration 2

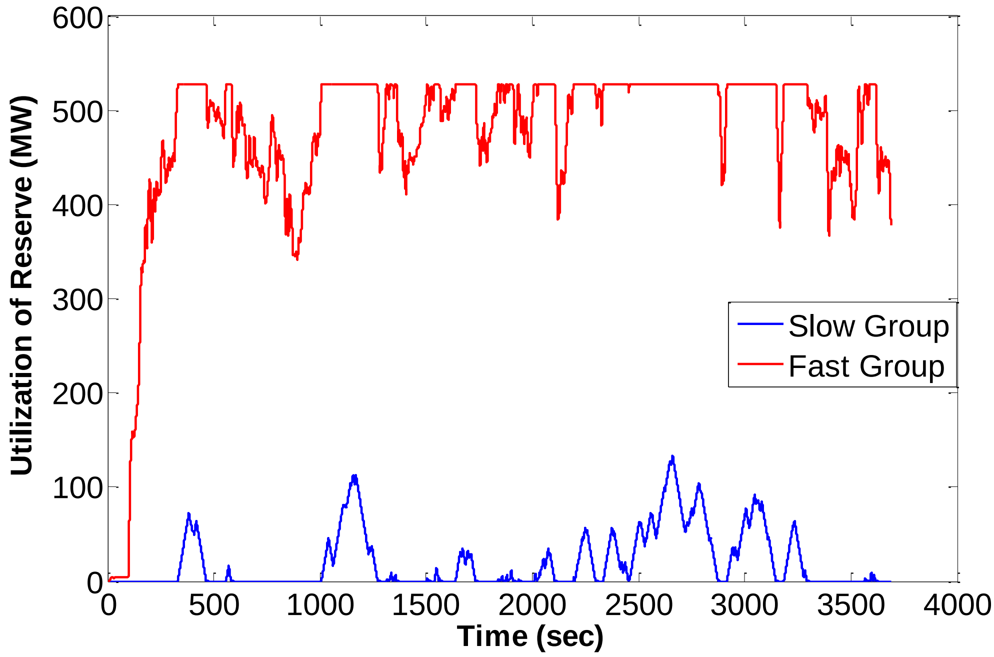


Figure 4.25 Case 3: Utilization of Reserve Groups in Iteration 2

For Iteration 3, total reserve constraint of 1000 MW is utilized in MILPROG. The amount of reserve selected to be 50 MW greater than the previous iteration as flow chart implies. As a result of MILPROG algorithm, 573 and 437 MW of reserve allocation is realized for fast and slow reserve groups, respectively.

Dynamic simulation results for Iteration 3 reveal errors, “% of abs(ACE)>175 MW” and “% of abs(ACE)>100 MW”, to be 8.33% and 31.22%, respectively. Corresponding figures for tie line flows and utilized reserve groups throughout the dynamic simulation are presented in Figure 4.26 and Figure 4.27, respectively.

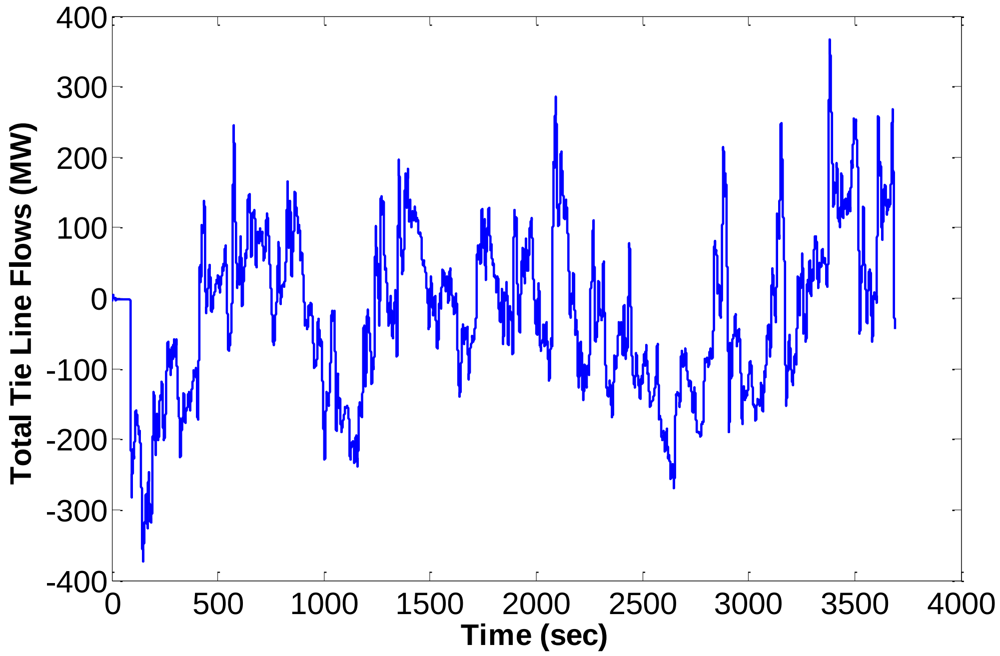


Figure 4.26 Case 3:Total Tie Line Flow in Iteration 3

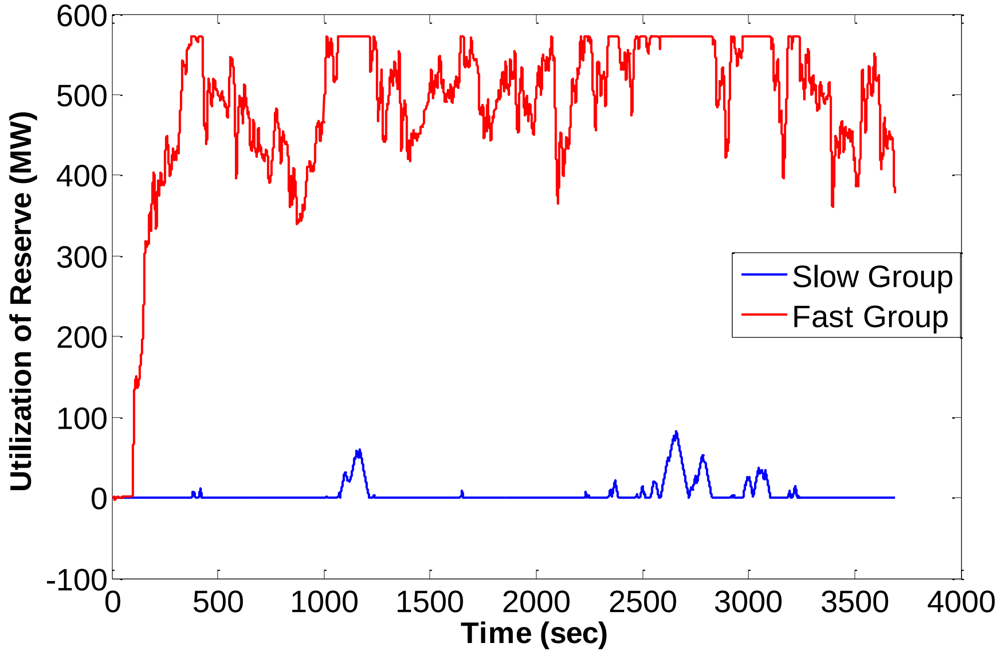


Figure 4.27 Case 3: Utilization of Reserve Groups in Iteration 3

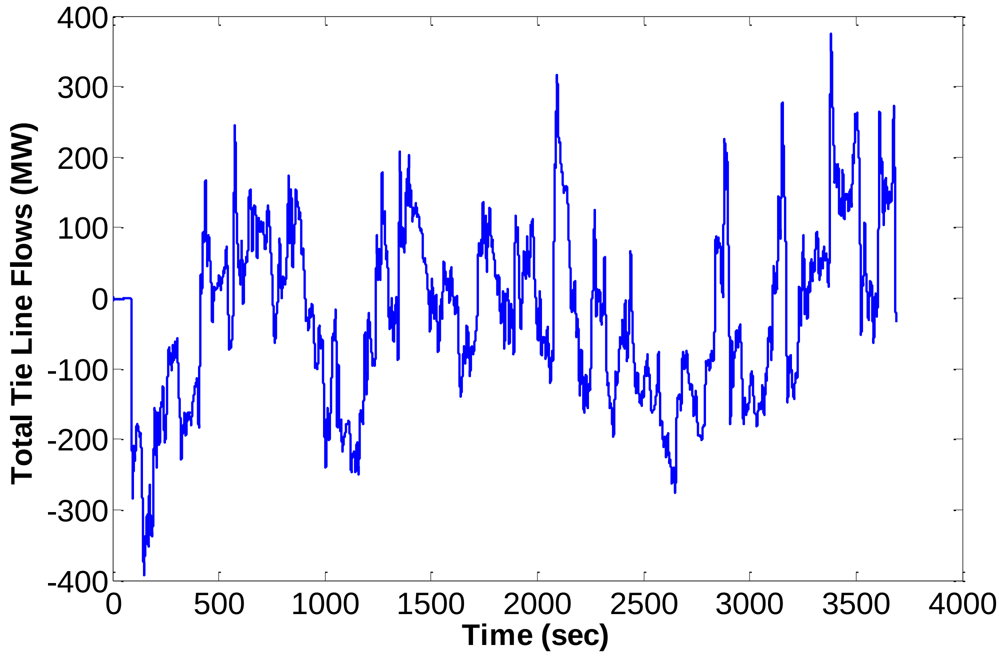


Figure 4.28 Case 3:Total Tie Line Flow in Iteration 4

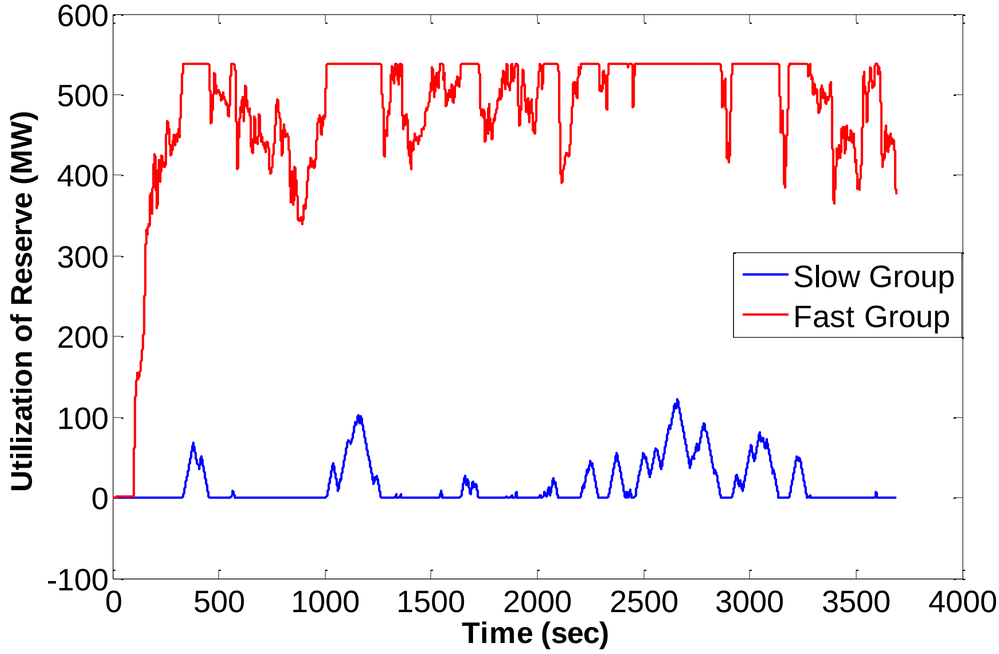


Figure 4.29 Case 3: Utilization of Reserve Groups in Iteration 4

In Iteration 3 satisfactory results are obtained. Next step is to search for an alternative dispatch with less cost. Therefore total amount of reserve constraint is adjusted to be the arithmetical average of the total reserve amounts of existing optimum solution and the last unsatisfactory iteration. Therefore, for Iteration 4, total reserve constraints is 975 MW. Dynamic simulation results of Iteration 4 shows that 975 MW of total reserve is not sufficient to meet ACE criteria. Before determining the optimum determination and allocation of the amount of reserve, another alternative with increased amount of fast reserve capacity must be considered.

For the next iteration, a new constraint regarding the fast reserve capacity is utilized in MILPROG in order to search for a solution with less cost. The amount of fast reserve capacity at this iteration is selected to be greater than the allocated fast reserve capacity of the existing solution by 25 MW. Resultant commitment is obtained via MATLAB. However, cost of the commitment in fourth iteration is greater than the existing solution. Therefore no dynamic simulation is required to validate the AGC performance of the proposed iteration. Commitment in Iteration 3 provides the optimum solution for this case. Summary of the iteration results throughout Case 3 is given in Table 4.8.

Table 4.8 Summary of Case 3

Iteration No	Total Reserve (MW)	Fast Reserve (MW)	% of abs(ACE)>175 MW	% of abs(ACE)>100 MW	Cost (TL)
1	900	482	12.61	40.61	12,312
2	950	527	10.72	38.56	44,111
3	1000	573	9.33	31.22	79,756
4	975	537	10.42	36.64	49,986
5	915	598	No Simulation Necessary	No Simulation Necessary	99,797

CHAPTER 5

CONCLUSION

Voltage and frequency are the two main quantities indicating the quality of an electrical power system. Therefore, steadiness of these quantities carries crucial importance in the operation of the network. In order to achieve it, voltage and frequency control systems are established in the power system. Voltage control is achieved by means of three different hierarchical stages, namely; primary, secondary and tertiary voltage control. With this control strategy, voltage levels along the grid are maintained within the acceptable limits determined by the grid code.

Frequency control of a power system deals with the maintaining balance between generated and consumed power. As being a dynamic system, power systems have been subject to wide variety of disturbances starting from minor changes in load to loss of considerable amount of generation. Therefore, the balance between generation and consumption must be tracked and controlled continuously. This is achieved by utilizing frequency control mechanisms which are realized in four different hierarchical stages.

Primary frequency control of a generating unit is a local automatic control provided by primary control circuits and consists of a precisely defined change in the power output of that specific unit in response to a frequency deviation from its set value. Hence, upon a disturbance in the system, all generators in the synchronous area sense the deviation in the frequency and give response by changing their power outputs.

After the establishment of a successful synchronous connection of Turkish network with ENTSO-E, borders of the European synchronous area were extended. Any disturbance in a specific point in the synchronous area is supported by all the generators in the synchronized system as a consequence of primary frequency control principle. However, each control area should feed its own load. Therefore, this requirement brings the necessity of tie line flow control between countries and this is achieved by the implementation of secondary frequency control systems. Secondary frequency control not only controls the tie line flow but also maintains the frequency at its nominal value.

Primary control mechanism functions as changing the units' power output to stop the deviation of frequency from its nominal value upon a mismatch between generation and consumption. However, the frequency will not be able to recover to its nominal value without a supplementary action taken by secondary control mechanism.

As being a part of an interconnected electricity network, secondary frequency control mechanism, which is realized by the utilization of an Automatic Generation Control System, plays a crucial role in maintaining the system frequency at its nominal value and keeping the active power flows through interconnection lines at their scheduled values. Challenge of achieving these two goals mainly originates from the existence of rapidly changing loads in the system i.e., EAFs, which create significant deviations in the frequency of the network and undesired power flows on tie lines. Therefore, performance of the AGC system is very important in order to keep the undesired power flow on tie lines within acceptable limits, i.e., ACE criteria.

In December 2011, electricity market in Turkey is established according to electricity market law and the day-ahead market started to operate. Bids of GENCOs in day-ahead market not only determine the next day's generating schedule but also effect the provision of secondary frequency control reserve. After settlement of the day-ahead market, secondary frequency control reserve capacity is formed among AGC participants via load increment and decrement orders, namely; YAL and YAT orders. Complexity of selecting AGC participants in most economical way for a specified amount of reserve arises due to high number of participants and the constraints of the participants upon providing reserve support. Manuel calculations in order to find most economical allocation of the reserve among participants is time consuming and prone to miscalculations because of the size of the problem.

Moreover, determination of the amount of secondary frequency control reserve is another issue to be decided. In order to operate the AGC system in a cost effective way, sufficient amount of reserve on an hourly basis should be decided. This is achieved by the system operators in National Load Dispatch Center with regard to their experience and knowledge. However, a systematical approach is needed for the optimal determination of the amount of secondary frequency control reserve and allocating it among participating units of secondary frequency control system in an economic manner.

In this thesis, a systematic approach to guide system operators in determination of the amount of reserve support and allocation among AGC participants considering ACE criteria is aimed. For that purpose, an iterative algorithm to determine the amount of reserve with minimum cost while satisfying the ENTOE-E criteria regarding Area Control Error (ACE) is developed. Cost minimization of the reserve support is conducted based on the price bids of the power plants participating in the AGC system in the day-ahead electricity market. Mixed integer linear programming function of MATLAB is utilized regarding the constraints of the participants upon providing secondary reserve support with minimum cost.

On the other hand, satisfaction of ACE criteria is validated by dynamic simulations conducted using DigSilent. The dynamic model used in this study is a simplified ENTSO-E model which is utilized to assess the performance of Turkish AGC system. Besides dynamic models of the generators in the system, load disturbance data to be applied to the system is also important for testing the developed algorithm.

It is observed that undesired tie line flows are highly correlated with the electric arc furnace loads which change rapidly in nature. For that reason, real measurements from several EAFs are obtained from TEİAŞ in order to form the set of test data.

From the simulated cases, it is observed that the reserve requirement for the hour of operation at interest is proportional with the amount of arc furnace demand. Therefore, provided secondary reserve capacity should vary with the changing demand to prevent excessive allocation of secondary reserve in order to be more economic while satisfying ACE criteria. Moreover, allocation of the total reserve among slow and fast responding reserve groups affects the performance of AGC. According to price bids of the participants, it is also possible to find a dispatch with increased percentage of fast reserve allocation and less amount of total reserve with less cost. An example of such a situation is simulated in Case 1 of the study.

Price optimization section of the developed algorithm has been tested in cooperation with TEAİŞ system operators, and they accepted to use the algorithm as a subsidiary tool for determining the AGC participants for secondary reserve support on hourly basis in a market environment. Following this, implementation process of this algorithm to TEAİŞ online system, where actions regarding the provision of secondary frequency control reserve are performed, has started and still ongoing.

As a future work to integrate the algorithm more effectively into the decision process of operators, working schedule of arc furnaces on an hourly basis is required. As the time being, this schedule is obtained for some specific days such as national holidays. Therefore, this process must be extended to cover each day of the year. With this integration, determination of the amount of reserve on an hourly basis is aimed. Moreover, allocating secondary reserve capacity more than sufficient will be prevented.

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APPENDIX - A

EQUIVALENT GENERATORS REPRESENTING ENTSO-E NETWORK

In this appendix, equivalent generators used to represent the electric power network of ENTSO-E member countries are presented.

Table A.1 Generators Representing European Network

Name	**Grid**	**Nominal Power (MW)**
PPE1	Benelux	15,995
PPE2	Benelux	16,332
PPE3	Bulgarian	2,776
PPE4	Bulgarian	2,063
PPE5	Bulgarian	2,064
PPE6	Bulgarian	1,217
PPE7	German	1,699
PPE8	German	2,544
PPE9	German	8,820
PPE10	German	6,752
PPE11	German	5,713
PPE12	German	6,752
PPE13	German	8,211
PPE14	German	6,191
PPE15	German	2,597
PPE16	German	31,481
PPE17	German	6,887
PPE18	German	2,558
PPE19	German	3,101
PPE20	Danish	4,326
PPE21	French	10,776
PPE22	French	8,002
PPE23	French	2,433
PPE24	French	2,193

Table A.1 (Cont'd)

Name	Grid	Nominal Power (MW)
PPE25	French	3,948
PPE26	French	18,158
PPE27	French	1,710
PPE28	French	13,235
PPE29	French	3,993
PPE30	French	5,695
PPE31	French	13,235
PPE32	French	11,952
PPE33	Italian	8,422
PPE34	Italian	3,681
PPE35	Italian	3,859
PPE36	Italian	6,608
PPE37	Italian	9,657
PPE38	Italian	6,525
PPE39	Italian	5,481
PPE40	Italian	6,318
PPE41	Italian	4,190
PPE42	Italian	2,692
PPE43	Croatian & Slovenian	2,886
PPE44	Croatian & Slovenian	3,213
PPE45	Croatian & Slovenian	5,424
PPE46	Croatian & Slovenian	2,169
PPE47	Croatian & Slovenian	5,812
PPE48	Croatian & Slovenian	2,094
PPE49	Croatian & Slovenian	1,673
PPE50	Croatian & Slovenian	3,371
PPE51	Croatian & Slovenian	4,311
PPE52	Polish	8,307
PPE53	Polish	2,151
PPE54	Polish	4,957
PPE55	Polish	3,544
PPE56	Polish	4,087
PPE57	Polish	2,313
PPE58	Portuguese	4,829
PPE59	Portuguese	4,820
PPE60	Romanian	1,500
PPE61	Romanian	2,850
PPE62	Romanian	2,835
PPE63	Romanian	2,360
PPE64	Swiss	3,231
PPE65	Swiss	4,450
PPE66	Swiss	4,461

Table A.1 (Cont'd)

Name	Grid	Nominal Power (MW)
PPE67	Spanish	5,466
PPE68	Spanish	4,847
PPE69	Spanish	3,630
PPE70	Spanish	8,986
PPE71	Spanish	6,576
PPE72	Spanish	3,219
PPE73	Spanish	6,060
PPE74	Spanish	6,452
PPE75	Spanish	10,857
PPE76	Czech & Slovakian	6,591
PPE77	Czech & Slovakian	5,273
PPE78	Czech & Slovakian	3,851
PPE79	Hungarian	3,055
PPE80	Hungarian	3,492
PPE81	Austrian	2,910
PPE82	Austrian	1,905
PPE83	Austrian	2,980
PPE84	Austrian	1,490

APPENDIX - B

SOME EXAMPLES OF EAF DEMAND ON HOURLY BASIS

In this Appendix, information regarding a typical demand curve of EAFs is given in order to give an insight to the reader. Plots are prepared by using actual SCADA measurements provided by TEAİŞ on a typical day in summer.

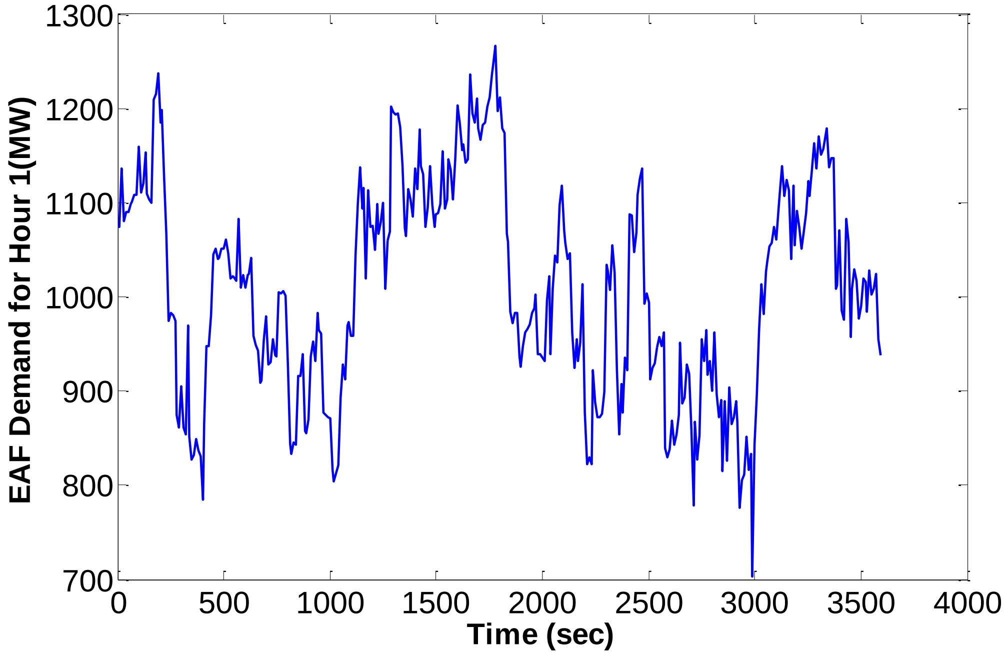

Figure B.1 EAF Demand for Hour 1

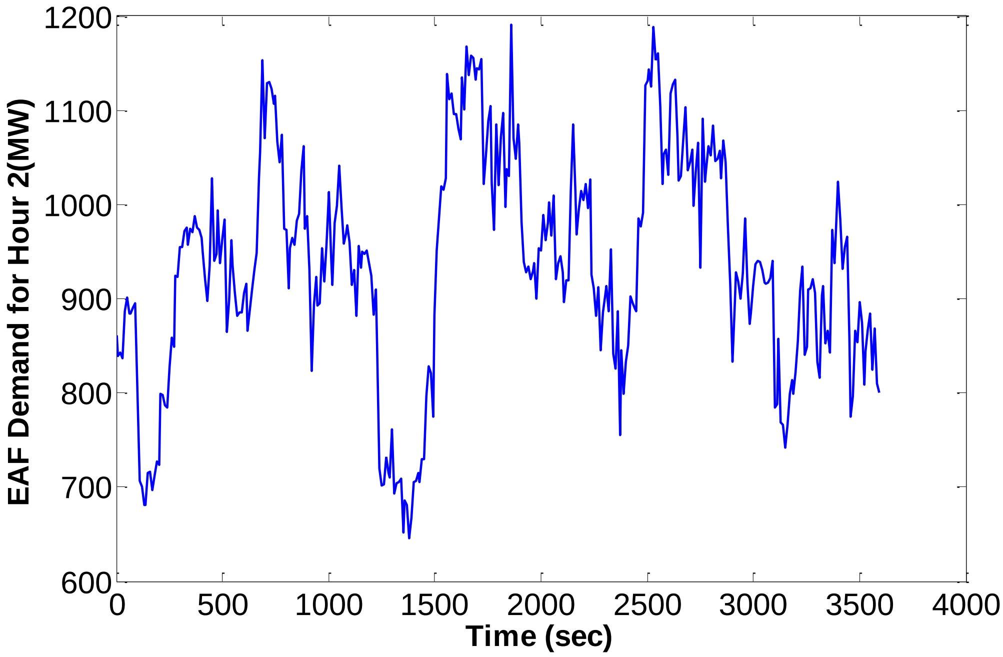

Figure B.2 EAF Demand for Hour 2

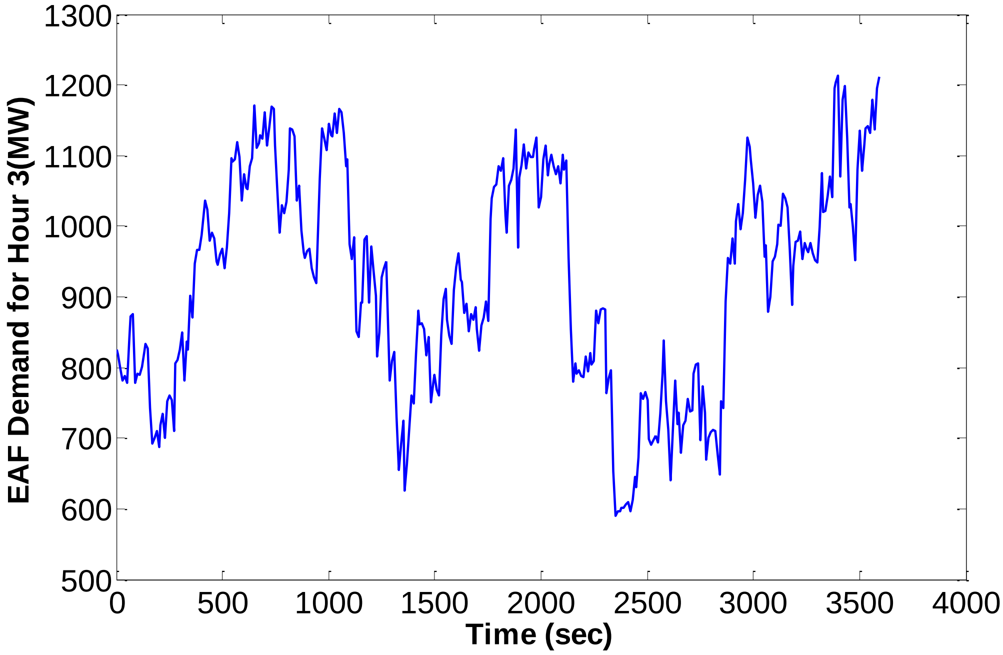

Figure B.3 EAF Demand for Hour 3

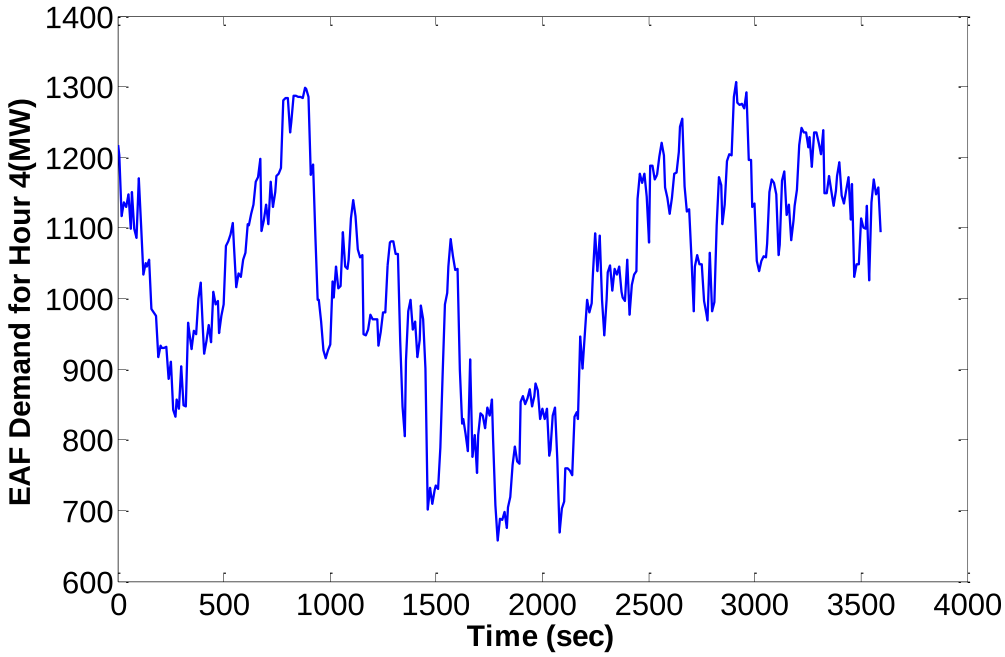

Figure B.4 EAF Demand for Hour 4

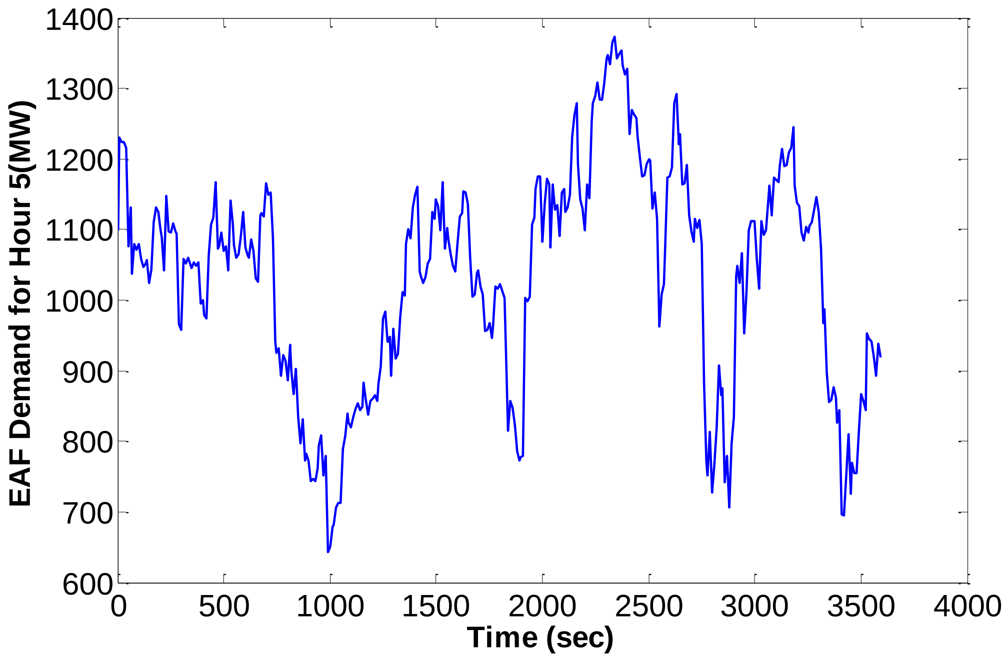

Figure B.5 EAF Demand for Hour 5

APPENDIX - C

ALLOCATION OF SECONDARY FREQUENCY CONTROL RESERVE AMONG AGC PARTICIPANTS

In this part, allocations of fast and slow reserve groups of the selected AGC participants for the simulated scenarios are presented for each iteration of each case.

Table C.1 Allocation of Reserve Groups for Case 1

	Iteration 1		Iteration 2		Iteration 3		Iteration 4	
	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group
PP1	100	0	100	0	100	0	100	0
PP2	80	0	80	0	80	0	80	0
PP3	0	0	0	0	0	0	0	0
PP4	0	0	0	0	0	0	0	0
PP5	40	0	40	0	40	0	40	0
PP6	0	0	10	3	0	0	10	0
PP7	0	0	0	0	0	0	4.75	0
PP8	0	0	0	0	0	0	10	0
PP9	0	0	0	0	0	0	0	0
PP10	0	0	10	28	10	16	10	0
PP11	1	0	0	0	0	0	10	0
PP12	30	145	30	145	30	145	30	0
PP13	0	0	0	0	0	0	0	0
PP14	0	0	0	0	0	0	0	0
PP15	0	0	0	0	0	0	0	0
PP16	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP17	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP18	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP19	0	0	0	0	0	0	0	0
PP20	0	0	0	0	0	0	0	0
PP21	7.5	14.5	7.5	14.5	7.5	14.5	7.5	14.5
PP22	13.5	10.5	13.5	10.5	13.5	10.5	13.5	10.5
PP23	0	0	0	0	0	0	0	0
PP24	0	0	0	0	0	0	0	0
PP25	22.5	8.5	22.5	8.5	22.5	8.5	22.5	0
PP26	33.5	0	33.5	0	33.5	0	33.5	0
PP27	0	0	0	0	0	0	0	0
PP28	18	20	18	20	18	20	18	20
>TOTAL	357.25	242.75	376.25	273.75	366.25	258.75	401	89.25

Table C.2 Allocation of Reserve Groups for Case 2

	Iteration 1		Iteration 2		Iteration 3		Iteration 4	
	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group
PP1	60	0	60	0	60	0	60	0
PP2	105	5	60	0	105	5	150	0
PP3	0	0	0	0	0	0	0	0
PP4	0	0	0	0	0	0	0	0
PP5	40	0	40	0	40	0	40	0
PP6	10	16.5	10	16.5	10	23.5	9.75	0
PP7	10	28	10	28	10	28	0	0
PP8	10	28	10	28	10	28	10	0
PP9	0	0	0	0	0	0	0	0
PP10	10	28	10	28	10	28	0	0
PP11	10	28	10	28	10	28	10	0
PP12	30	145	30	145	30	145	30	145
PP13	0	0	0	0	0	0	0	0
PP14	0	0	0	0	0	0	0	0
PP15	0	0	0	0	0	0	0	0
PP16	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP17	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP18	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP19	0	0	0	0	0	0	0	0
PP20	0	0	0	0	0	0	0	0
PP21	7.5	15	7.5	15	7.5	15	7.5	15
PP22	13.5	10.5	13.5	10.5	13.5	10.5	13.5	10.5
PP23	18	14	18	14	0	0	0	0
PP24	0	0	0	0	0	0	0	0
PP25	22.5	8.5	22.5	8.5	22.5	8.5	22.5	0
PP26	33.5	0	33.5	0	33.5	0	33.5	0
PP27	0	0	0	0	0	0	0	0
PP28	18	20	18	20	18	20	18	20
>TOTAL	409.25	390.75	364.25	385.75	391.25	383.75	416	234.75

Table C.3 Allocation of Reserve Groups for Case 3

	Iteration 1		Iteration 2		Iteration 3		Iteration 4		Iteration 5	
	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group	Fast Group	Slow Group
PP1	80	0	80	0	125	5	80	0	170	0
PP2	100	0	145	5	145	5	145	5	145	0
PP3	0	0	0	0	0	0	0	0	0	0
PP4	0	0	0	0	0	0	0	0	0	0
PP5	40	0	40	0	40	0	40	0	40	0
PP6	10	27.5	10	27.5	10	27.5	10	27.5	0	0
PP7	10	27	10	27	10	27	10	27	10	0
PP8	10	27	10	27	10	27	10	27	9.25	0
PP9	0	0	0	0	0	0	0	0	0	0
PP10	10	17.5	10	17.5	10	17.5	10	4.5	1	-1
PP11	0	0	0	0	0	0	10	28	0	0
PP12	30	139	30	139	30	139	30	139	30	139
PP13	45	33.5	45	33.5	45	33.5	45	33.5	45	33.5
PP14	7.5	16.5	7.5	16.5	7.5	16.5	7.5	16.5	7.5	16.5
PP15	6	18.5	6	18.5	6	18.5	6	18.5	6	18.5
PP16	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP17	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP18	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75	3.75	14.75
PP19	0	0	0	0	0	0	0	0	0	0
PP20	0	0	0	0	0	0	0	0	0	0
PP21	7.5	13.5	7.5	13.5	7.5	13.5	7.5	13.5	7.5	13.5
PP22	13.5	10.5	13.5	10.5	13.5	10.5	13.5	10.5	13.5	10.5
PP23	18	14	18	14	18	14	18	14	18	14
PP24	0	0	0	0	0	0	0	0	0	0
PP25	22.5	8.5	22.5	8.5	22.5	8.5	22.5	8.5	22.5	8.5
PP26	33.5	0	33.5	0	33.5	0	33.5	0	33.5	0
PP27	10	0	10	0	10	0	10	0	10	0
PP28	18	20	18	20	18	20	18	20	18	20
>TOTAL	482.75	417.25	527.75	422.25	572.75	427.25	537.75	437.25	598	317.25