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ISSUES IN AUTOMATIC GENERATION CONTROL POWER SYSTEM OPERATION WITH DEREGULATION

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Abstract

Main purpose of the AGC (automatic generation control) or LFC (load frequency control) is to balance the total system generation against system load and losses so that the desired frequency and power interchange with neighboring systems are maintained. With the process of Unbundling, in a restructured power system, the engineering aspects of planning and operation have to be reformulated although essential ideas remain the same. DISCO Participation Matrix (DPM) helps in the visualization and implementation of the contracts between the GENCOs and DISCOs.

Introduction

Any mismatch between generation and demand causes the system frequency to deviate from scheduled value, So main purpose of AGC is to balance the total system generation against system load so that the desired frequency is maintained.

An unbundled structure contrasts with the so-called vertically integrated utility of today where all tasks are coordinated jointly under one umbrella with one common goal, that is, to minimize the total costs of operating the utility. The main objectives of real-time operation in today's industry are to (1) schedule maintenance of power plants, (2) turn them on and off and (3) change generation outputs as required to supply the predicted system demand at least O&M cost. Under the normal operating conditions each power company generally schedules its own plants for some assumed power exchange with the neighboring systems. Power exchange with the neighbors is only modified in real time for sharing reserves under unexpected contingencies.

Today's power industry is a restructured power industry so our main objective is to control the frequency under deregulated environment. The specific objectives are:

1. To discuss economic dispatch for traditional and new power industry.
2. To develop simulation model for each component of AGC loop.
3. To develop model for two area AGC system.
4. To develop AGC model after deregulation considering two cases.

Power System Restructuring

Control areas are the bodies setup for the purpose of regulating power exchanges across tie-lines interconnecting pairs or group of utilities. Another important function of control areas is to regulate system frequency.

Competitive Organizational Structures

An unbundled structure contrasts with the so-called vertically integrated utility of today where all tasks are coordinated jointly under one umbrella with one common goal, that is, to minimize the total costs of operating the utility.

Service Unbundling

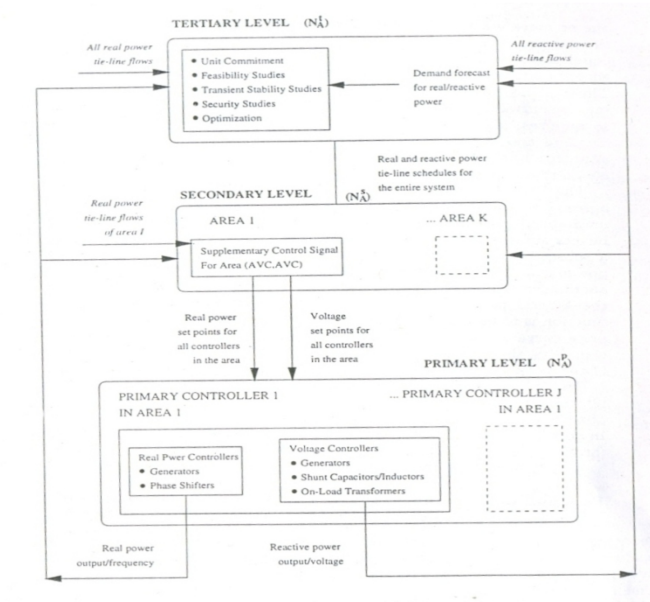
Some of the main services that can be unbundled for separate tariffication are:

The generation of real power, real time load-following and transmission loss generation, standby spinning reserve, short-term spinning reserve for security purposes, load frequency control, VAR generation and interruptible loads.

These services can be operated by physically distinct and independently operated enterprises, the level and, in certain cases, the location of these services need to be coordinated. This is required because of the strong physical coupling and physical restrictions among all these quantities.

Tasks in Today's Power Industry

Small random deviations from anticipated demand are tracked by automatic generation control (AGC). Typically, a large system has only a handful of AGC units directly dedicated to system wide regulation in response to small load random variations. A typical hierarchical information/control structure in operating today's large power system is shown in figure below:



Figure(1)

All power plants participate in unit commitment (tertiary level), while only some, relatively flexible plants are regulating units in each control area (secondary control).

Meeting Demand in New Industry: Primary Electricity Market (Task 1)

In the new industry, the predicted system demand will be supplied competitively by many producers. One could identify several different mechanisms for providing generation to where it is needed.

Conventional Economic Dispatch

The economic dispatch program is routinely used for changing the power generated every 5-15 minutes to fit the anticipated demand in near real time.

The conventional economic dispatch assumes demand to be a given input for which generation use is optimized under the constraint that total generation meets total demand.

- It is straightforward to generalize this formulation to account for price-elastic demand.
- This generalization is concerned with task 1 in the new industry.

Decentralized Economic Dispatch

When competitive bilateral transactions take place, each party has as its main objective to maximize its profit, max $\prod_i(P_i)$,Where $\prod_i = pP_i – C_i(P_i)$ stands for the profit made by the market participant i through some sort of trading process, given (known) p. if a market participant is a generator then,

$$\prod_i(P_{gi}) = p^* P_{gi} - C_i^*(P_{gi}) \qquad (1)$$

While if it is a load,

$$\prod_i(P_{di}) = - (p^* P_{di} - C_i^*(P_{di})) \qquad (2)$$

In the above equations, p is the price paid, C_i is the cost function. Thus, under perfect conditions, when the market converges to a single electricity price for both sellers and buyers, p, one can maximize $\prod_i$ to yield

$$dC_{g1}/dP_{g1} = = \ldots = dC_{ng}/dP_{ng} = dC_{d1}/dP_{d1} = \ldots = dC_{nd}/dP_{nd} = p$$

This is simply obtained by each market participant optimizing own profit/benefit for the assumed (exogenous) market price p. the process of bilateral decisions will stabilize at the system wide economic equilibrium under a perfect information exchange among all mps.

The Decentralized Unit Commitment

Consider first a simplified solution with a single generator owner which sells electricity into a day ahead spot market. This problem is much simpler than the stochastic unit commitment problem in today's industry, as there is only one generator to consider, and all of the random disturbances are presumed to be reflected by the price at which power is sold. The generator owner is assumed to be a price taker in a competitive market place.

The generation owner must take unit commitment decisions typically by certain time day ahead, before actually knowing the spot price of the next hour. After the spot price is known, the generator decides how much power to sell (dispatch) in order to maximize profit. The only control for the problem is $u_k(1)$ whether to turn on or off at stage k. the generator level P_{gi} may be regarded as a function of the control $u_k(1)$

and the expected price p_k. If $u_k(1) = 0$, then $P_{gi} = 0$. If $u_k(1) = 1$, then P_{gi} at stage k is set to maximize the expected profit,

$$\prod_k = p_k^* P_{gi} - C_i^*(P_{gi}) \qquad (3)$$

For a quadratic cost function $C_i^*(P_{gi}) = a_i^*P_{gi}^2 + b_i^*P_{gi} + c_i$ and not taking into consideration the generation limits power quantity that maximizes profit at stage k is easily found to be

$$P_{gi} = ((p_k – b_i)/2^*a^*i) \qquad (4)$$

Here is assumption is made that p_k is an exogenous input to the decision making process, namely that market prices are uncorrelated at different decision making stages. The same process gets computationally more involved when price is modeled as a state variable.

The result i.e. the overall profit should be higher with its additional variable. The problem, of course gets computationally more involved.

Generalized Economic Dispatch

The generalized economic dispatch is then the problem of scheduling both generation and demand so that the total generation and the demand cost is minimized as follows,

$$\min_{P_g, P_d} \left(\sum_{i=1} C_i * (P_{gi}) + \sum_{j=1} C_j * (P_{dj})\right)$$

such that total generation equals total load. A necessary condition for solving this basic economic dispatch problem is

$$dC_1/dP_1 = = \ldots.. = dC_{ng}/dP_{ng} = dC_{d1}/dP_{d1} = \ldots.. = dC_{nd}/dP_{nd}$$

above criteria is used as a general measure of static efficiency in any competitive industry where it is often referred to as the (negative of) the social welfare. Both generation and demand cost functions C_i (P_{gi}) and C_i (P_{di}) are analogous. In addition, since both generation and load have hard upper and lower limits, the optimum must account for such restrictions

Load Frequency Control Conventional Scenario

An electric energy system must be maintained at the desired operating level characterized by nominal frequency, voltage profile and load flow configuration.

In an interconnected power system, Load Frequency control (LFC) and Automatic Voltage Regulator (AVR) equipment are installed for each generator. The schematic diagram of the LFC loop and AVR loop is as shown in figure below. The excitation system time constant is much smaller than the prime mover time constant and its transient decay much faster and does not affect the LFC dynamic. Thus the coupling between the LFC loop and the AVR loop is negligible and the load frequency and excitation voltage control are analyzed independently.

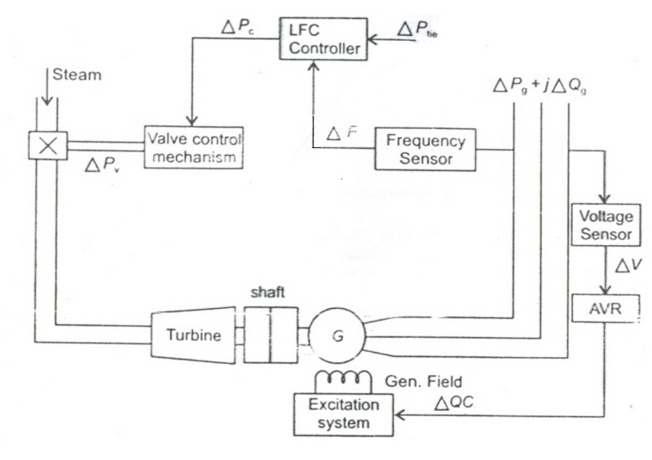


Figure 3.1: Schematic diagram of LFC and AVR of a synchronous generator

Concept of Control Area

A control area is defined as power system, a part of system or a combination of systems to which a common generation control is applied. The electrical interconnections within each control area are very strong as compared to ties with the neighboring areas. In normal steady state operation each control area of a power system should strive to meet its load demand. Simultaneously each control area of a power system should participate in regulating the frequency of the system.

The two basic inter-area regulating responsibilities of each control are:

When system frequency is on schedule, each area is expected automatically to adjust its generation to maintain its net transfers with other areas on schedule, thereby absorbing its own load variations. So long as all areas to do so, scheduled system frequency as well as net interchange schedules for all areas are maintained.

When system frequency is off schedule, because one or more areas are not fulfilling this equality responsibility, other areas are expected automatically to shift their respective net transfer schedule proportionally to the system frequency deviation and in direction to assist the deficient areas and help to restore system frequency. The extent's of each area shift of net interchange schedule is programmed by its frequency bias setting.

Cooperative assistance between areas is one of the planned benefits of interconnected operation. But when the assistance is unscheduled, it is obtained at the expense of departures of system frequency and area net interchange from their respective schedules.

Two Area Load Frequency Control

An extended power system can be divided into number of load frequency control areas interconnected by means of tie lines. Without loss of generality consider a two area case connected by a single tie line as show below.

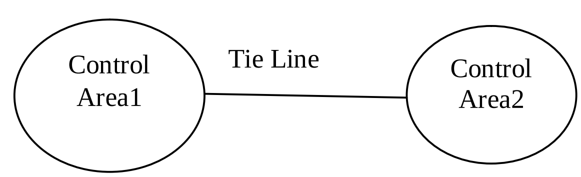


Figure 3.12: Two area power system

The control objective now is to regulate the frequency of each area and to simultaneously regulate the tie line power as per inter-area power contracts. As in the case of frequency, proportional plus integral controller will be installed so as to give zero steady state error in tie line power flow as compared to the contracted power. It is conveniently assumed that each control area can be represented by an equivalent turbine, generator and governor system. In an isolated area case the incremental power (ΔP_g - ΔP_d) was accounted for by the rate of increase of stored kinetic energy and increase in area load caused by increase in frequency. Since a tie-line transports power in or out of an area, this fact must be accounted for in the incremental power balance equation of each area.

Load Frequency Control with Generation Rate Constraints (GRC)

Load frequency control problem discussed so far does not consider the effect of the restrictions on the rate of change of power generation. In power systems having steam plants, power generation can change only at a specified maximum rate. The generation rate (from safety considerations of the equipment) for reheat units is quite low. Most of the reheat units have a generation rate around 3% per minute. Some have a generation rate around 5 to 10% per minute. If these constraints are not considered, system is likely to chase large momentary constraints are not considered, system is likely to chase large momentary disturbances. This results in undue wear and tear of the controller. Several methods have been proposed to consider the effect of GRC is considered, the system dynamic model becomes non-linear and linear control techniques cannot be applied for the optimization of the controller setting.

Load Frequency Control In A Restructured Power System

In a restructured power system, the engineering aspects of planning and operation have to be reformulated although essential ideas remain the same. The electric power business at present is largely in the hands of vertically integrated utilities (VIUs) which own generation-transmission-distribution systems that supply power to the customer at regulated rates. Such a configuration is shown in below figure 3.1 in which the large rectangular box denotes a VIU. The VIU is usually interconnected to other VIUs and this interconnection is almost always at the transmission voltage denoted in the figure as tie-lines. Thus, electric power can be bought and sold between VIUs along these tie-lines and moreover, such interconnection provides greater reliability. The major change that has happened is the emergence of independent power producer (IPPs) that can sell power to VIUs and these are also shown in below figure. Thus, at the square boxes in figure denote business entities which can buy and/or sell electric power.

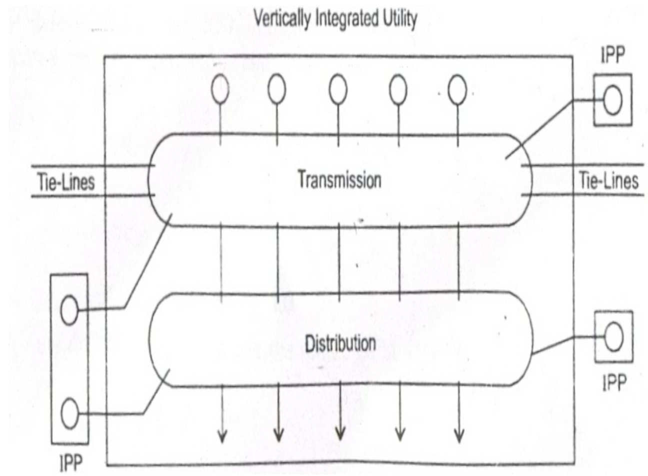


Figure 4.1: vertically integrated utility

Given the present situation, it is generally agreed that the first step in deregulation will be to separate the generation of power from the transmission and distribution, thus putting all the generation on the same footing as the IPPs. Figure 3.2 shows the deregulated utility structure. In this figure, GENCOs which will compete in a free market to sell electricity they produce. It can be assumed that the retail customer will continue for some time to buy from the local distribution company. Such distribution companies have been designated as DISCOs. The entities that will wheel this power between GENCOs and DISCOs have been designated as TRANSCOs. Although it is conceptually clean to have separate functionalities for the GENCOs, TRANSCOs and DISCOs, in reality there will exist companies with combined or partial responsibilities.

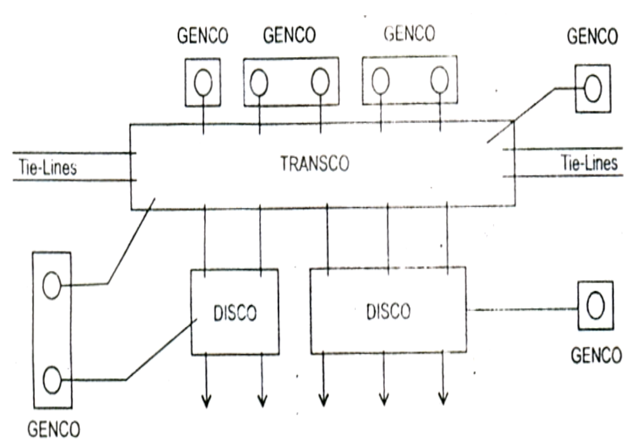
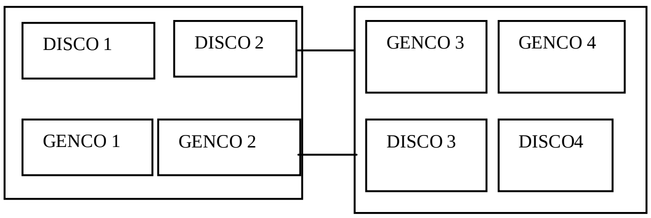


Figure 4.2: deregulated utility structure

With the emergence of the distinct identities of GENCOs, TRANSCOs, DISCOs and the ISO, many of the ancillary services of a VIU will have a different role to play and hence have to be modeled differently. Among these ancillary services is the Automatic Generation Control(AGC). In the new scenario, a DISCO can contract individually with a GENCO for power and these transactions will be made under the supervision of ISO.

Disco Participation Matrix (DPM)



Tie line

Area1 Area 2

Figure 4.3: two area power system in restructured

In the restructured environment, GENCOs sell power to various DISCOs at competitive prices. Thus, DISCOs have the liberty to choose the GENCOs for contracts. They may or may not have contracts with the GENCOs in their own area. This makes various combinations of GENCO-DISCO contracts possible in practice.

DPM is a matrix with the number of rows equal to the number of GENCOs and number of columns equal to number of DISCOs in the system. For the purpose of explanation, consider a two-area system in which each area has two GENCOs and two DISCOs in it. Let GENCO 1, GENCO 2, DISCO 1 and DISCO 2 are in area-1, and GENCO 3, GENCO 4, DISCO 3 and DISCO 4 are in area-2 as shown in figure 4.3.

The DPM of above figure can be given as:

	DISCO1	DISCO2	DISCO3	DISCO4
GENCO1	cpf $_{11}$	Cpf $_{12}$	cpf $_{13}$	cpf $_{14}$
GENCO2	cpf $_{21}$	Cpf $_{22}$	Cpf$_{23}$	cpf $_{24}$
GENCO3	cpf $_{31}$	Cpf $_{32}$	cpf $_{33}$	cpf $_{34}$
GENCO4	cpf $_{41}$	Cpf $_{42}$	cpf $_{43}$	cpf $_{44}$

DPM= Each entry in eqn. (3.1) can be thought of as a fraction of a total load contracted by a DISCO (column) toward a GENCO (row). Thus, the ij-th entry corresponds to the fraction of the total load power contracted by DISCO j from GENCO i. The sum of all the entries in a column in this matrix is unity. DPM shows the participation of a DISCO in a contract with a GENCO, and hence the "DISCO participation matrix". In eqn. 3.1, cpf ij refers to "contract participation factor". For the purpose of explanation, suppose that DISCO 2 demands 0.1 pu MW power, out of which 0.02 pu MW is demanded from GENCO 1, 0.035 pu MW from GENCO 2, 0.025 pu MW demanded from GENCO 3 \and 0.02 pu MW demanded from GENCO 4.

The column 2 entries in eqn. 3.1 can be easily defined as:

cpf $_{12}$= (0.02/0.1) = 0.20; cpf $_{22}$=(0.035/0.1) = 0.35;

cpf $_{32}$= (0.025/0.1) = 0.25; cpf $_{42}$ = (0.02/0.1) = 0.20;

also cpf $_{12}$+ cpf $_{22}$+ cpf $_{32}$+ cpf $_{42}$ = 1.0

other cpfs are defined easily to obtain the entire DPM. In general

Σ_i = cpf $_{ij}$ = 1.0

Block Diagram Representation

I will formulate the block diagram for a two area AGC system in the deregulated scenario. Whenever a load demanded by a DISCO changes, it is reflected as a local load in the area to which this DISCO belongs. This corresponds to the local loads ΔPL1 and ΔPL2 and should be reflected in the deregulated AGC system block diagram at the point of input to the power system block. As there are many GENCOs in each area, ACE signal has to be distributed among them in proportion to their participation in AGC. Coefficients that distribute ACE to several GENCOs are termed as " ACE participation factors". Note that

$$\sum_{i=1}^{NGENCO_j} a'_{ji} = 1.0$$

Where a'ji = participation factor of i-th GENCO in j-th area.

NGENCOj = number of GENCO in j-th area

Unlike the traditional AGC system, a DISCO asks or demands a particular GENCO or GENCOs for load power. These demands must be reflected in the dynamics of the system. Turbine and governor units must respond to this power demand. Thus, as a particular set of GENCOs are supposed to follow the load demanded by a DISCO to particular GENCO specifying corresponding demands. The demands are specified by cpfs (elements of DPM) and the pu MW load of a DISCO. These signals carry information as to which GENCO has to follow a load demanded by which DISCO.

The scheduled steady state power flow on the tie-line is given as: Scheduled

ΔP_{tie12} = (Demand of DISCOs in area-2 from GENCOs in area-1) – (Demand of DISCOs in area-1 from GENCOs of area-2) Scheduled

$\Delta P_{tie12} = \sum_{i=1}^{2} 1 \sum_{j=3}^{4} cpfij\, \Delta PL_j - \sum_{i=3}^{4} 1 \sum_{j=1}^{2} cpfij\, \Delta PL_j$

At any given time, the tie-line power error is defined as:

error actual scheduled

$\Delta P_{tie12} = \Delta P_{tie12} - \Delta P_{tie12}$

The tie-line power error vanishes in the stedy-state as the actual tie-line power flow reaches the scheduled power flow. This error signal is used to generate the respective ACE signals as in the traditional scenario:

$ACE_1 = B_1\, \Delta F_1 + \Delta P^{error}{}_{tie12}$

$ACE_2 = B_2 \Delta F_2 + \alpha_{12} \Delta P^{error}{}_{tie12}$

For two area system contracted power supplied by i-th GENCO is given as:

$\Delta P_i = \sum_{j=1}^{NDISCO=4} cpfij \, \Delta PL_j$ The block diagram of two area AGC system in a deregulated environment is shown in figure below:

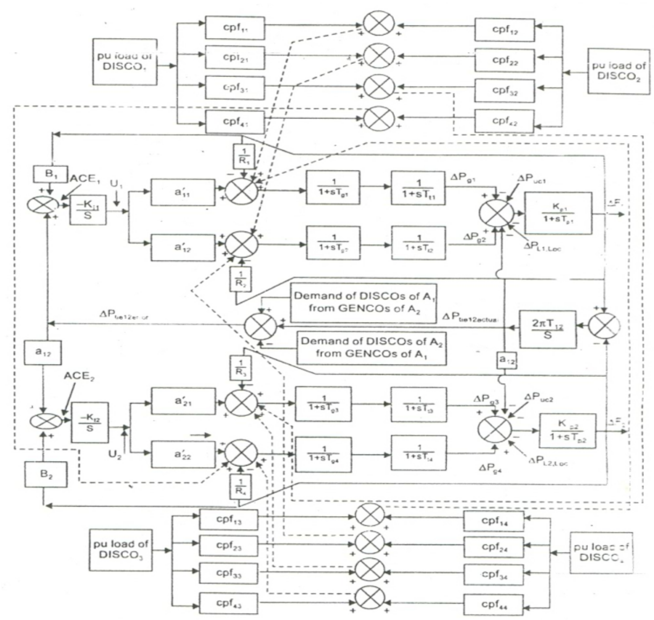


Figure 4.4: block diagram of two area deregulated power system

Conclusion

AGC provides a relatively simple, yet extremely effective method of adjusting generation to minimize frequency deviations and regulate tie-line flows. This important role will continue in restructured electricity markets. However some important modifications are necessary to cater for bilateral contracts that span control areas. Bilateral contracts can exist between DISCOs in one control area and GENCOs in other control areas. The scheduled flow on a tie-line between two control areas must exactly match the net sum of the contracts that exist between market participants on opposite sides of the tie-line (taking account of contract directions). If a contract is adjusted, the scheduled tie-line flow must be adjusted accordingly.
The concept of 'Disco Participation Matrix' (DPM) is introduced in this work. The DPM provides a compact yet precise way of summarizing bilateral contractual arrangements.
The modeling of AGC in a restructured environment must take account of the information flow relating to bilateral contracts. Clearly, contracts must be communicated between DISCOs and GENCOs. However it is also important that information regarding contracts is taken into account in establishing/adjusting the tie-line set points.

Acknowledgments

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Biographies

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