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Software development of Supplementary control of generating Systems network.

Olumuyiwa Oludare FAGBOHUN
Department of Electrical Engineering, Faculty of Engineering, Ekiti State University, Ado-Ekiti,Ekiti State, Nigeria.

Abstract:- Power systems networks usually consist of many generating units operating in parallel to supply electricity into a transmission system, some of these units are working at rated capacities while others are either working at no -load or inbetween. The power outputs from the generating stations and the frequency are made available to the generation control system for system control. At the control center, supplementary control of power system generation is implemented. This paper discuss the use of supplementary control information given by control Engineers on the allocation of generation, unit commitment, economic dispatch and other necessary parameters needed to make decisions on how the power balance on the system can be achieved. The software implementation of the information is developed, on a generalized system consisting of N generating units, for overall supplementary control of the whole system network at once. The software operates on an automated generating controller supervising the system stability. The supplementary control software program performs well in the computation of the change in power demand by consumers and in allocating demands with the use of the stations participation factors as required, and makes sure that allocation of power demands to generating stations does not exceed the available spinning reserves. The developed software in the event of a large load change (i.e> 1000MW) without enough spinning reserves, gives information about the magnitude of the demand to be shed at the load centers before the unit commitment problem is solved at the generating station, and also ensure the load change are distributed among the fast (i.e Gas fired stations) and low (Hydro stations) responding units, according to the pre-determined criteria.

Keywords:- *Demand, economic dispatch, frequency change, generation allocation, spinning reserves, synchronizing capacity, participating factors.*

I. INTRODUCTION

The electric power demand by consumers vary continually and it is necessary that the power generated be varied to achieve generation **-** load demand balance. The efficient control of the power system generation to meet the demand of its consumers at a given point in time occupies a very vital position. A typical daily load curve [1] is mostly influenced by a nation's social habits. For example, the load curves generally have their peaks in the evenings when most consumers are at home using most of their electrical appliances. This load curves are required on a daily basis by control Engineers to allocate generation to power stations, and are the most difficult to assess scientifically of all the various parameters of electrical power systems because of the non-linearity [2,3] in the demand of Electrical power experienced from time to time. Supplementary control by engineers at control centre of a system network involves the allocation of generation among the on-line units, so that power balance is achieved. Also the power outputs from the generating stations and the frequency are monitored at the generation control centre for decisions on status, new allocation of generation and control required to balance the network generation-load demand. This paper discuss the action of a control engineer from generation allocation to participating power centers. This action involves the unit commitment of systems, economic dispatch of units such that the total generating cost is minimized, base point and participation factors determination, all which is required for an efficient delivery of a quality power to consumers.

II .SUPPLEMENTARY CONTROL REQUIREMENTS

2.1. Generation Allocation

For systems where the control of power is carried out by the decisions and actions of engineers as opposed to systems in which the control and allocation is effected completely automatically the following steps are taken. The allocation of the required power among the generators has to be decided before the advent of the load which must be predicted.

An analysis is made of the loads experienced over the same period in previous years. Account is also taken of the value of the load immediately previous to the period under study and of the weather forecast. The probable load to be expected having been decided is allocated to the various generators.

The allocation is the result of the economic dispatch calculations [5] which is executed such that the total generation matches the load forecast plus expected transmission losses. The output from the economic dispatch calculation forms the base point of each generating unit.

The variation of individual generator output over a range of load is accomplished using base points and participation factors. The rate of change of each unit output with respect to a change in total generation is called the unit participation factors (Pf) [5,6]. These based points and participation factors are used as defined by

$P_{ides} = P_{ibase} + pf_1\Delta P_{tot}$ ……..1

Where $\Delta P_{tot} = P_{new} + \Sigma_f P_{ibase}$ ……2

And P_{ides} = new desire output from unit I

P_{ibase} = base point generation for unit I

Pf_{1m} = participation factor for unit I

ΔP_{tot}= change in generated power I

Pnew = new total generation.

2.2 Unit Commitment

The total power demand by consumers vanes continually, generally high during daytime and early evenings when industrial and residential loads are on and low during late evenings and early morning when most of the population is asleep. In addition, the use of electric power has a weekly cycle [2,5,7], the load being lower over weekend days than weekdays. To commit a generating unit is to "turn to on", that is, to bring the unit up to speed, synchronize it to the system [8], so it can deliver power to the network. The problem with committing enough units and leaving them on - line is one of economics. It is quite expensive to run too many generating units at a time and a great amount of money can be saved by turning units off (de-committing them) when they are not needed.

In order to determine the number of generating units required to participate in supplying a given load at an optimum cost for a given period an economic dispatch technique is used. Also the committed units must carry a sufficient amount of generation reserves[4,8] to make up for the loss of other units in a specified time period. This is called the spinning reserves.

Spinning reserve is used to describe the total amount of generation available from all units synchronized (i.e. spinning) on the system units the present demand. The reserves are allocated to obey certain rules of which the prominent ones are:

(1). The reserve must be a given percentage of forecasted peak demand.

(2). It must be capable of making up the loss of the most heavily loaded unit in a given period of time.

(3). The reserve is calculated as a function of the probability [8,9] of not having sufficient generation to meet demand.

The reserves must also be allocated among the fast responding units and slowresponding units to allow the automatic generation control system to restore frequency to its nominal value in the event of a generating unit outage or load change.

2.3 Economic dispatch of generating units

Economic dispatch of generating units is a method of scheduling generation among the committed generating units, such that the total generating cost is minimized subject to the following constraints:

(a) That the power generated equals the total system demand PD. where the total system demand is the sum of the received load (P_D) and line losses (P_L) i.e. $P_G= P_R+ P_L$.

(b) That the power output of each unit must be greater than or equal to the minimum power output permitted and must also be less than or equal to the maximum power output permitted on that particular unit.i.e$P_{i,min}<P_{i,max}$

For a system consisting of N thermal units connected to a busbar serving an electrical load PR through a transmission network, the input to each unit shown as Fiin Figure 2, represents the cost rate of the unit. The output of each unit and the sum of the costs of each of the individual units is equal to the total cost rate of the system. Mathematically [1,4,7] the problem may be stated very concisely as an objective function F_T, which is equal to the total cost of supplying the indicated load.

In order to establish the necessary conditions for an extreme value of the objective function the constraint function, is multiplied by an undetermined multiplier, and added to the objective function. The resulting equation is known as the Lagrange function [6,7,9].

$$L = F_T + \lambda\phi \qquad \text{..............................3}$$

$$F_T = F_1 + F_2 + F_3 \ldots\ldots + F_N$$

$$\sum_{i=1}^{N} F_i\,(P_i)$$

and

$$\phi = P_R + P_L - \sum_{i=1}^{N} P_i = 0 \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 4$$

The first derivative of the Lagrange's function with respect to each of the independent variables set equal to zero, gives the necessary conditions for an extreme value of the objective function,
that is

$$\frac{\partial L}{\partial P_i} = \frac{dF_i}{dP} - \lambda\left(1 - \partial P_L \big/ \partial P_i\right) = 0 \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots 5$$

Or

$$\frac{dF_i}{DP_i} + \frac{\lambda \partial P_L}{\partial P_i} = \lambda \qquad \ldots\ldots\ldots\ldots\ldots\ldots 6$$

$$\frac{dF_i}{dP_i} L_i = \lambda$$

Where

$$L_i = \left(\frac{1}{1 - \frac{\partial P_i}{\partial P_i}} \right) \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots 7$$

In equation 5, $\delta P_L / \delta P_i$is the incremental transmission loss. The first method of solving equation 6 is known as the penalty factor method discussed at some length by [8,9] equation 6 is rewritten as

$dF_i/dP_i\ (L_i) = \lambda$

where $L_i = (1)/\ (1 - \delta L/\ \delta P_i)$ is the penalty factor of plant i, The necessary condition for the existence of a minimum cost operating condition for the generating power system is that the incremental cost rates multiplied by the penalty factors of each unit must be equal to some undetermined value, λ

The other basic approach to the solution of equation 6 is to incorporate the load flow equations as essential constraints in the formal establishment of the optimization problem. This general approach is known as the optimal load flow.

2.4. Base point and participation factors

The economic dispatch problem has to be solved repeatedly by moving the generators from one economically optimum schedule to another as the load changes by a reasonably small amount. Starting from a given schedule, the base point, the scheduler assume a load change and investigate how much each generating unit needs to be moved (i.e. "participate" in the load change) in order that the new load be served at the most economic operating point.

Given both the first and second derivatives in the cost versus power output function, (i.e. both FI and FI exist), as the unit load is changed by an amount ~Pi, the system incremental cost moves from 'AD to ('AD + ~'A). For a small change in power output on this simple unit

~'Ai = ~'A = FI (P_i^O) ~Pi

This is true for each of the units on the system so that

$\Delta P_i = \Delta\lambda / F_i$ fori = 1,2,....N 8

The total change in generation is the sum of the individual unit changes.
that is

$$\Delta P_D = \Delta P_I + \Delta P_2 + \ldots\ldots\ldots + \Delta P_N$$

$$= \Delta\lambda \sum_i (1/F_i) \qquad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 9$$

The earlier equation 8 can then be used to find the participation factor for each unit as follows,

$$\frac{(\Delta P_I)}{\Delta P_D} = \frac{(1/F_I)}{\sum_i (1/F_I)} \qquad \ldots\ldots\ldots\ldots\ldots 10$$

III. Software development for supplementary control of Systems.

For the supplementary software development, the necessary information required are;

(1). Rated megawatt output for each committed units.
(2). The system frequency.
The information for the Power Holding Company Nigeria, [PHCN] system used as a practical system were received/taken from the operation planning section of the National control centre, Osogbo, Nigeria. The system consists of 14 major generating stations with 71 generating units.
For a generating station A, If Ai is the capacity of each committed unit, then the total generating capacity of the station would be

$$\sum_{i=1}^{L} A_i$$

Where N is the number of generating units available in station A. For the second station, the total generating capacity is

$$\sum_{i=1}^{M} B_i$$

and for thestation the total generating capacity will be

$$\sum_{i=1}^{P} Z_i$$

Hence, the total generating capacity of the practical system will be equal to the sum of the generating capacities of each station. i.e,

Total generating capacity $L = \sum_{i=1}^{L} A_i + \sum_{i=1}^{M} B_i + \ldots\ldots + \sum_{i=1}^{P} Z_i$

where L≠M≠P and L, M, P > 1.
Due to some constrains, some units may not be allowed to work at rated output. Therefore if ti represents the fraction of the rated capacity of each unit allowed for maximum output generation, then the maximum output from station A will be

$$\sum_{i=1}^{L} t_{ai} A_i$$

For station B, the maximum output will be M

$$\sum_{i=1}^{M} t_{bi} B_i$$

and for the Nth station

$$\sum_{i=1}^{P} t_{zi} Z_i$$

where t ai t bi to t zi is the fractions for station A, B, to Z respectively.
Thus the synchronized generation from station A becomes, L

$$\sum_{i=1}^{L} S_i t_{ai} A_i$$

whereS, = 0 or 1 for I = 1, 2, ... , L determines whether the unit is synchronized (i.e. S, = 1) to the system to take part in power generation or otherwise.
If rai is the fraction of tai required for base generation by station A to satisfy the allocated generation, then station A generates

$$P_{Ai(base)} = \sum_{i=1}^{L} r_{ai} t_{ai} S_i A_i$$

Where $0.25 \leq r_{ai} t_{ai} \leq 1.0$

And for the Nth station $P_{Ni(base)} = \sum_{i=1}^{P} r_{zi} t_{zi} S_i Z_i$

For $0.25 \leq r_{zi} t_{zi} < 1.0$

This amount of power is generated to the system network at base load. The factor rai tai must not be less than the minimum fraction of the generator output of each unit synchronized i.e. rai tai ~ 0.25. Hence the spinning reserves for the station will be the difference between the synchronized generation output and the base generation of the station.

$$\sum_{i=1}^{L} S_i t_{ai} A_i - \sum_{i=1}^{L} r_{ai} S_i t_{ai} A_i$$

$$= \sum_{i=1}^{L} S_i t_{ai} A_i (1 - r_{ai})$$

This equation is used to calculate the spinning reserves available at each of the generating stations committed to the system.
For station A, if Ri is the percent regulation of each generating units, then the station percent regulation becomes,

$$\frac{1}{R(1)} = \frac{1}{R_1} + \frac{1}{R_2} + \frac{1}{R_3} + \ldots.. + \frac{1}{R_i}$$

Thus for an I stations, the system percent regulation will be

$$\frac{1}{R} = \frac{1}{R(1)} + \frac{1}{R(2)} + \ldots.. + \frac{1}{R(I)}$$

The base MV A assumed for each station is 50MV A and all calculations is based on these assumption. The frequency deviation FD = Measured frequency - Reference frequency. Expressing this in per unit gives $\Delta w = FD/50$ where w is the change in frequency.The participation factors are varied for each 30MW change in demand. The change in power demand is calculated from $\Delta P_L = -\Delta w(1/R + D)$ where R is the system percent regulation of equation and D is the system droop.
Hence for each station I, the required change in power DE(I) is calculated from the equation.

$$DE(I) = \Delta P_L \times PF(I)$$

Where PF(I) is the participation of the I^{th}station for a given load change.

Load shedding information is programmed to occur only when there is no enough spinning reserves on the system to cater for a load change. A margin of 0.1 Hz frequency deviation is given such that no change in generation is required from the station between the line frequency of 49.9 and 50.1Hz. This margin takes care of random variations of frequency due to noise effects along the network. The program flowchart is as shown in figure 1.

IV. PERFORMANCE OF THE SUPPLEMENTARY CONTROL SOFTWARE.

The supplementary control software program performs well in the computation of the change in power demand by consumers and in allocating demands with the use of the stations participation factors as required. The simulation results of the software program for different input frequencies is as shown in Tables 1 to 4.

Table 1: simulation result for the supervisory control program
Time of the day : 6.00a.m.

Station code number	Station name	Generating capacity	Number of generators	Synchronized generators	Syncronised capacity (MW)	Generation allocation	Spinning reserves(MW)
1.	Jebba	570	6	4	200	200	0
2.	Delta	312	14	8	116	116	0
3.	Kainji	760	8	4	365	365	0
4.	Afam	660	17	10	516	290	226
5.	Sapele GT	720	6	2	600	360	240
6.	Sapele ST	300	4	3	225	125.5	112.5
7.	Ajaokuta	210	2	2	210	105	105
8.	Egbin (gas)	1320	6	1	880	726	154
9.	Ijora	67	4	0	42	19.5	22.5
10.	Oji river	30	4	2	12.5	12.5	12.5
	Total for the hour	4849	71	36	3179.5	2306.5	872.5

Table 2: Desired change in generation for different input frequencies for the hour

Frequency(Hz) Time / Station Code	51.779 6.00am	48.936 6.08am	47.173 6.10am	52.371 6.22am	49.924 6.30am	49.117 6.38am	46.333 6.41am
1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.000	0.0000	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	0.0000	26.0041	34.5459	-19.3157	0.0000	17.6946	-19.1121
5	-50.7252	34.6722	52.9704	-57.9472	0.0000	0.0000	-25.4828
6	0.0000	26.0041	62.1827	-38.6315	0.0000	26.5418	-19.1121
7	0.0000	0.0000	27.6368	0.0000	0.0000	0.0000	0.0000
8	-86.9575	0.0000	41.4551	-77.2829	0.0000	0.0000	0.0000
9	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10	-7.2464	0.0000	11.5153	0.0000	0.0000	0.0000	0.0000

Table 2: Desired change in generation for different input frequencies for the hour continues

Frequency(Hz) Time / Station Code	**50.059 6.48am**	**49.10 6.53am**	**49.117 6.55am**	**49.924 6.58am**	**46.333 7.00am**
1	0.0000	0.0000	0.0000	0.0000	0.0000
2	0.0000	0.0000	0.0000	0.0000	0.0000
3	0.0000	0.0000	0.0000	0.0000	0.0000
4	0.0000	21.9960	21.5805	0.0000	44.8107
5	0.0000	29.3280	28.7740	0.0000	68.7098
6	0.0000	21.9960	21.5805	0.0000	80.6593
7	0.0000	0.0000	0.0000	0.0000	35.8485
8	0.0000	0.0000	0.0000	0.0000	53.7729
9	0.0000	0.0000	0.0000	0.0000	0.0000
10	0.0000	0.0000	0.0000	0.0000	12.5000

Table 3: simulation result for the supervisory control program Time of the day : 9.00a.m.

Station code number	**Station name**	**Generating capacity**	**Number of generators**	**Synchronized generators**	**Syncronised capacity (MW)**	**Generation allocation**	**Spinning reserves(MW)**
1.	Jebba	570	6	4	378.4	289.2	89.2
2.	Delta	312	14	8	232	138	94
3.	Kainji	760	8	4	530	345	185
4.	Afam	660	17	10	484	360.5	123.5
5.	Sapele GT	720	6	2	360	240	120
6.	Sapele ST	300	4	3	225	187.5	37.5
7.	Ajaokuta	210	2	2	210	210	0
8.	Egbin (gas)	1320	6	1	660	220	440
9.	Ijora	67	4	0	0	0	0
10.	Oji river	30	4	2	15	15	0
	Total for the hour	4849	71	36	3094.4	2005.2	1089.2

Table 4: Desired change in generation for different input frequencies for the hour

Frequency(Hz) Time / Station Code	49.275 9.00am	51.333 9.12am	49.257 9.18am	48.475 9.26am	47.331 9.32am	50.099 9.40am	52.117 9.43am
1	0.0000	0.0000	12.1059	18.6355	0.0000	0.0000	-20.6957
2	14.7658	0.0000	0.0000	0.0000	32.6152	0.0000	0.0000
3	0.0000	-26.0628	15.1324	24.8473	0.0000	0.0000	-37.9423
4	11.8127	0.0000	0.0000	0.0000	54.3586	0.0000	17.2465
5	32.4848	-27.1488	0.0000	43,4828	50.0099	0.0000	48.2902
6	0.0000	-16.2893	18.1589	6.2118	36.9639	0.0000	-31.0437
7	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
8	0.0000	-39.0942	15.1324	31.0592	43.4869	0.0000	-34.4930
9	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000

Table 4: Desired change in generation for different input frequencies for the hour continues

Frequency(Hz) Time / Station Code	50.629 9.48am	49.911 9.52am	49.890 9.55am	51.998 9.58am	40.111 10.00am
1	0.0000	0.0000	2.2403	-19.5324	0.0000
2	-12.8106	0.0000	0.0000	0.0000	84.366
3	0.0000	0.0000	0.0000	-35.8095	153.1839
4	-10.2485	0.0000	6.7210	-16.2770	120,6100
5	-28.1834	0.0000	0.0000	-45.5757	115.3612
6	0.0000	0.0000	0.0000	-29.2987	30.2251
7	0.0000	0.0000	0.0000	0.0000	0.0000
8	0.0000	0.0000	0.0000	-32.5541	152.4881
9	0.0000	0.0000	0.0000	0.0000	0.0000
10	0.0000	0.0000	0.0000	0.0000	0.0000

The developed software make sure that allocation of power demands to generating stations does not exceed the available spinning reserves. In the event of a large load change (i.e> 1000MW) without enough spinning reserves, it gives information about the magnitude of the demand to be shed at the load centers before the unit commitment problem is solved at the generating stations. Also the load change are distributed among the fast (i.e Gas fired stations) and low (Hydro stations) responding units.

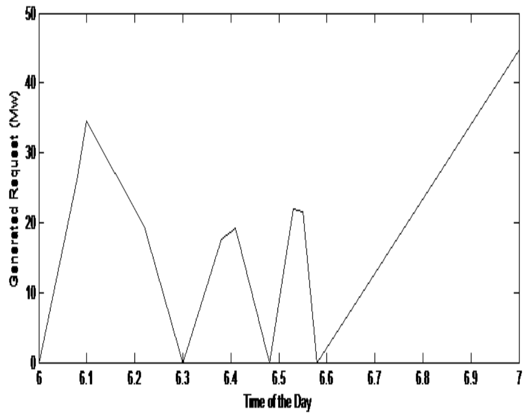

Figure 1: generating request from station1 Based on demand within an hour

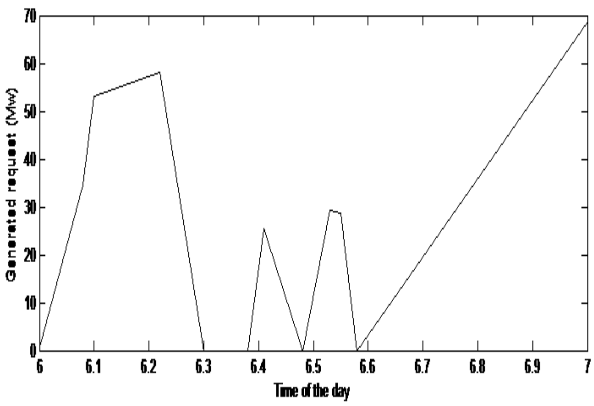

Figure 2: generating request from station 2 Based on demand within an hour

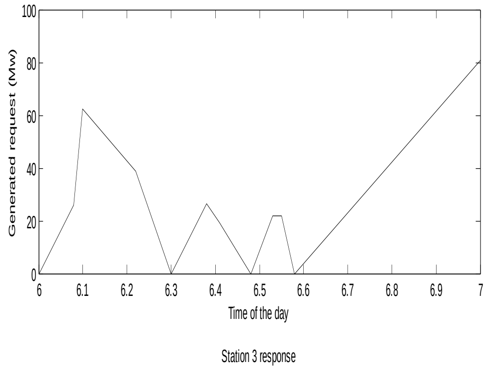

Figure 3: generating request from station 3 Based on demand within an hour

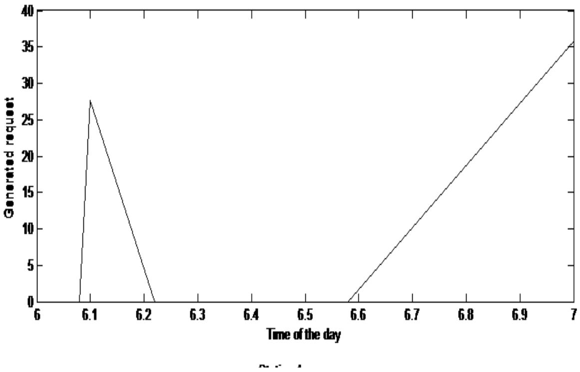

Figure 4: generating request from station 4 Based on demand within an hour

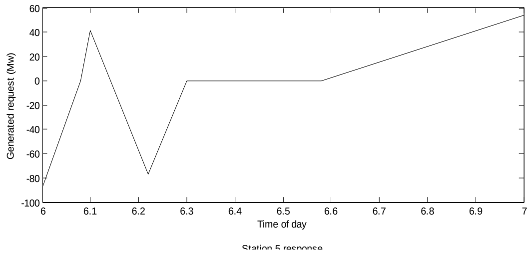

Figure 5: generating request from station 6 Based on demand within an hour

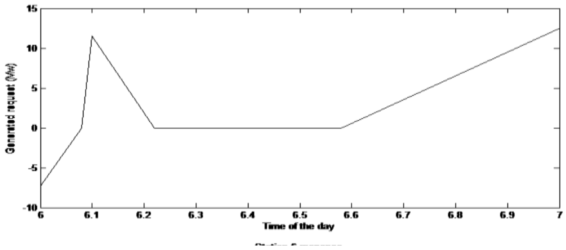

Figure 6: generating request from station 6 Based on demand within an hour

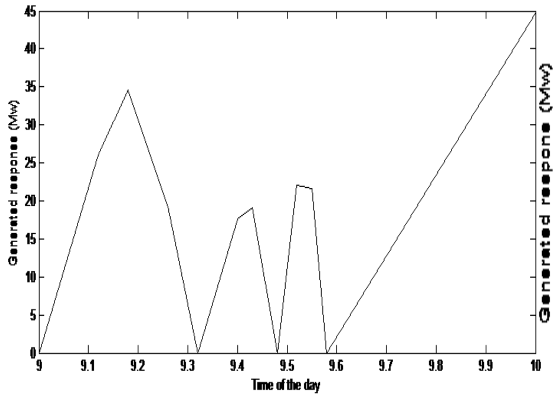

Figure 7: generating request from station 1 Based on demand within an hour

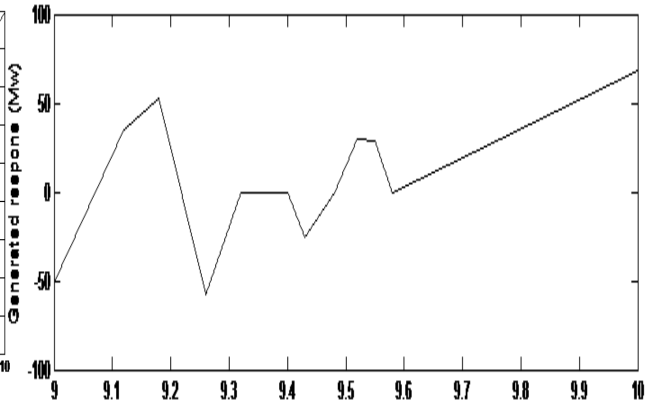

Figure 8: generating request from station 2 Based on demand within an hour

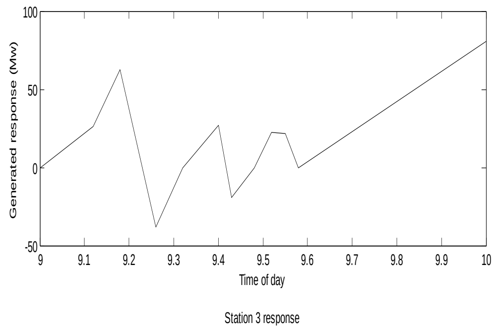

Figure 9: generating request from station 3 Based on demand within an hour

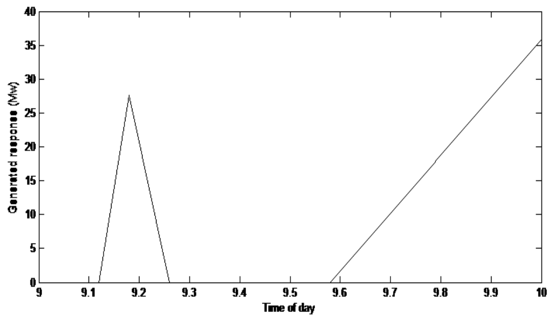

Figure 10: generating request from station 4 Based on demand within an hour

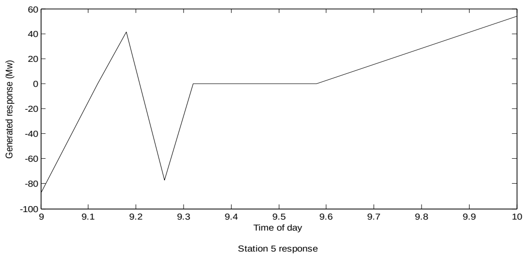

Figure 11: generating request from station 5 Based on demand within an hour

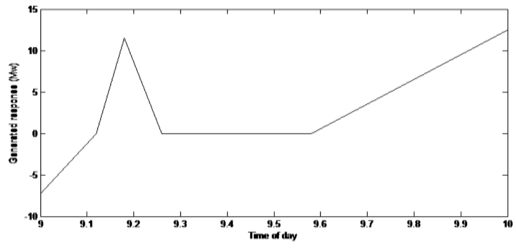

Figure 12: generating request from station 6 Based on demand within an hour

V. CONCLUSION

The simulation of the supplementary control software shows that the input - output response time of the program is in the range of 10 milli- second on Acer Aspire 5572N system. When the hardware of the supervisory control logic is connected with read and write times of about 8us [4,9], it was found that the sampling of the system line frequency will be taking place once every second. Also, as the magnitude of the load continues to vary second by second, the line frequency, which is directly proportional to the changes in load demand is also varying and this is sampled every second by the develop software to make appropriate decisions as described in this work. The software performs well in monitoring and maintaining the frequency of the system network at or very close to the nominal value (i.e.49.9 - 50.1 Hz or + 0.2). The standard requirement for normal operation is a deviation of - 1.5 from the nominal value and, the National control center in Nigeria aims at maintaining the frequency at - 0.4 at all times.

Also the conventional method of load shedding instructions to load centers, is expected to be totally eliminated since the required power has been generated and the frequency is maintained within the acceptable range, thereby resulting in a continuous efficient and uninterrupted electricity supply to consumers at all times and an improved control mechanism.

Exception to the above, with the use of the software, is when there is no enough spinning reserves from the generating stations in which case, a fraction of the load demand will be shed off before the unit commitment problem is solved for the hour.

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