The study of dependency of power system stability on system inertia constant for various contingencies

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Abstract—**Disturbances to an interconnected power system lead to fluctuation of electrical quantities such as voltage, current and frequency. Generally abnormalities lead to fall of system frequency and the initial reaction of the power system to a disturbance is called inertial response of the system which is a function of system inertia constant (H), the higher the system inertia constant the slower the rate of change of frequency (ROCOF) for a system hence the bigger value of this constant refers the higher stability of the system. This paper presents a differential equation for ROCOF, where ROCOF is an inverse function of system inertia constant as well as comparison of system stability for different types of faults inside a system for various inertia constants. Based on the results of the study, it can be concluded easily that the system stability for different contingencies is very much dependent on the overall H constant of the system.**

Keywords—CYME PSAF, Inertia constant, Multi machine system, ROCOF

I. INTRODUCTION

The moment of inertia is defined as the product of rotating mass and the square of the distance from the center of rotation. A rotating mass has characteristics of an energy storage device. During acceleration, energy is stored, and during deceleration, it is released. In the case of a negative frequency deviation, during acceleration, the system's moment of inertia works against frequency control efforts because it is storing rotational energy; during deceleration the moment of inertia helps to control frequency by releasing previously stored rotational energy. The equivalent moment of inertia of a system is the combination of moment of inertias of the connected power generating units, including both the prime mover and the generator. Due to the rotating mass of the large spinning machines such as rotor, driving turbine shaft etc, energy store in generators. When a disturbance occurs e.g. the unanticipated loss of a generator, addition of load or combined effect of load addition and generation loss, the stored energy is released to the system to make the system stable.

The frequency behaviour of a generator depends on different parameters such as generator inertia constant, generator damping constant, governor gain and electrical distance of the disturbance from the generator [1], when a disturbance occurred in the network. It is observed that generator damping and governor gain has no significant effect on the initial frequency behaviour of a generator after a disturbance. Minimum frequency deviations belong to the generators with larger inertia constant (H), greater electrical distance from the location of disturbance and less electrical distance from the slack generator. After calculating amount of overloads and disturbing conditions the amount of loads to be shed is determined. It is described in [2] that immediately after the load change impact of power system network, the machines share the impacts immediately according to their electrical proximity to the point of impact and after a short transient period of time machines share the impact according to their inertia constant (H).

In [3], it is described that disturbances in an interconnected power system lead to frequency deviations in grid. The frequency deviation is primarily characterized by the amount of inertia of the system. The inertia constant (H) describes the characteristics of the system; the bigger value of this constant refers the higher stability of the system. It is apparent that the system frequency stability is very much dependent on the overall H constant of the system. For a multi machine system the H constant increases with the increase of number of machines connected to the system. That means a system with higher number of active generators will have higher inertia constant than a system with lower number of active generators hence the larger system shows more stable operation than a smaller system which has been presented in [4].

II. INERTIA CONSTANT AND ROCOF

The inertia constant of a power system is denoted by H, which is defined by the ratio of stored kinetic energy in mega joules at synchronous speed to rating of the machine in MVA [5].

That is,

$$H = \frac{Storedkineticenergyinmegajoulesatsynchronousspeed}{MachineratinginMVA}$$

$$H = \frac{\frac{1}{2} J {\omega_{sm}}^2}{G_{mach}} \qquad (1)$$

Where, H= inertia constant in MWs/MVA,
J= moment of inertia in kg-m^2 of the rotating mass.
ω= nominal speed of rotation in rad/s

G_{mach} = MVA rating of the machine.

Ifthetorqueproducedbyamachine'sprimemoverdoesnotmatchthetorqueproducedbythegeneratormagneticfields the machine willaccelerate ordecelerate. Abasicequation relating torque toacceleration is:

$$T_a = J\frac{d\omega}{dt} \text{ N-m} \quad (2)$$

Where, T_a= Accelerating Torque

J= moment of inertia in kg-m^2 of the rotating mass.

ω= nominal speed of rotation in rad/s

Substituting the value of J from equation (1)

$$P_a = T_a\omega_{sm} = \frac{2H\, G_{mach}}{\omega_{sm}}\frac{d\omega}{dt} \text{ N} \quad (3)$$

Where P_a is the accelerating power.

If P_a is divided by rated G_{mach}, then accelerating power is converted to per unit accelerating power andi f ωis dividedbyrated angular frequencythenωchanges to per unit angular frequency. Equation (3)canbe convertedinto per unit accelerating power:

$$P_{apu} = 2H\frac{d\omega_{pu}}{dt}\text{pu} \quad (4)$$

This can be solved for rate of change of frequency (ROCOF)

$$\frac{d\omega_{pu}}{dt} = \frac{T_{a\,pu}}{2H} \quad (5)$$

Unlessfrequencydrifts farfromthebasefrequencywecanapproximateperunittorque asbeingthesameasperunitpower,soT_a maybereplacedby P_a and similarly ω_{pu} can be replaced by f_{pu}, hence the equation will be

$$\frac{df_{pu}}{dt} = \frac{P_{a\,pu}}{2H} \quad (6)$$

The significance of the above equation is that it is used to determine the ROCOF of the system and $P_{a\,pu}$is defined as follows [62]

$$P_{a\,pu} = \frac{\Delta P}{P_{gen}} \quad (7)$$

$$\text{Hence, } P_{a\,pu} = \frac{P_{gen}-P_{load}}{P_{gen}} \quad (8)$$

Where, ΔP = Megawatt of load addition or generation lost.

P_{gen}= Generation of the system

P_{load}= Connected load of the system.

The solution of the differential equation (2.6) can be written as:

$$f(t) = f_0[1 + (\frac{P_{a\,pu}}{2H})t] \quad (9)$$

Where, f_0= Initial Frequency (System Frequency)

This equation can be solved for the time that it takes to reach a given frequency:

$$t(f) = \frac{\frac{f}{f_0}}{\frac{P_{apu}}{2H}} \quad (10)$$

The following figures shows the ROCOF for various combinations of $P_{a\,pu}$and H and it is clearly depicted from the following figures that for a higher value of H the ROCOF will be lower.

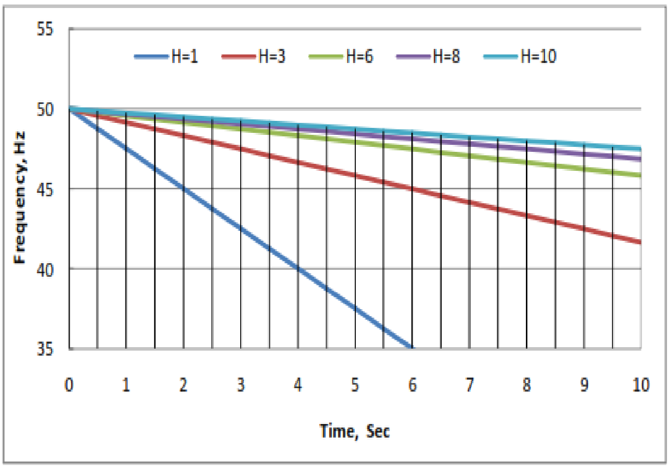

Fig. 1. ROCOF for different Inertia Constant of a System where P_a=0.10 pu.

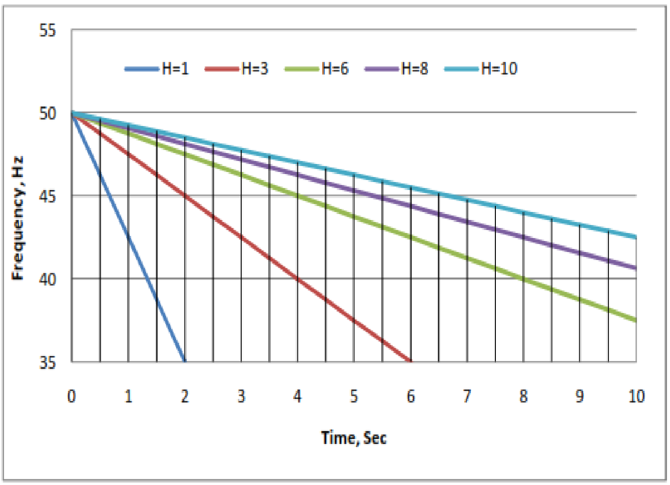

Fig. 2. ROCOF for different Inertia Constant of a System where P_a=0.30pu.

The inertia constant H has a characteristic value or a range of values for each class of machines. Table I lists inertia constants of some typical machines [6].

Table I: Inertia constant for different types of machines

Types of Machines	Inertia Constant H (s)	Types of Machines	Inertia Constant H (s)
Turbine Generator Condensing: 1800 rpm 3000 rpm Non condensing: 3000 rpm	 9-6 7-4 3-4	**Synchronous Motor:** with Load varying from 1.0 to 5.0 and higher for heavy flywheels	2.00
Waterwheel Generator Slow speed: <200 rpm High speed : >200 rpm	 2-3 2-4	**Diesel Engine**	1-3
Synchronous Condenser Large Small	 1.25 1.00	**Load, Motor**	0.5-3

It is observed from Table I that the value of H is considerably higher for steam turbo generator than for water wheel generator.For a multi machine system H constant of the overall system is defined by the following equation [4],

$$H_{system} = \frac{\sum H_i G_i}{\sum G_i} \qquad (11)$$

Where, $\sum G_i = G_{system}$

H_i = H constant of the i-th machine.

G_i = the apparent power of the i-th machine.

Here the inertia constant of loads are included as well. The value of H for loads varies with type of load; though motors load have some inertia but resistive load do not have any inertia. From the above equation it can be easily depicted that with the increase of number of machines the value of inertia constant will be increased hence the stability of larger system will be higher.

III. SIMULATION RESULTS AND DISCUSSIONS

Two islands with different numbers of generators as well as different amount of generations and loads are simulated using CYME PSAF. Names of the islands are Dhaka and Khulna-Barisal Island with 58 and 15 numbers of generators respectively. The load and generation in Dhaka region is 2100 MW whereas the amount for Khulna-Barisal region is 605 MW. As most of the generators in both regions are same type and the total number of generator is much higher in Dhaka region it is expected that the equivalent inertia constant for Dhaka region is higher. The offline calculation also shows the same result. Fig. 3. shows the fall of frequency in Dhaka region in case of load addition when no relay is being activated to shed load; case A refers system frequency remains within an accepted range up to a load addition of 13.55% (284 MW) whereas case B refers in case of 15.89 % (334 MW) load addition, here the system frequency goes below the accepted range making the system unstable.

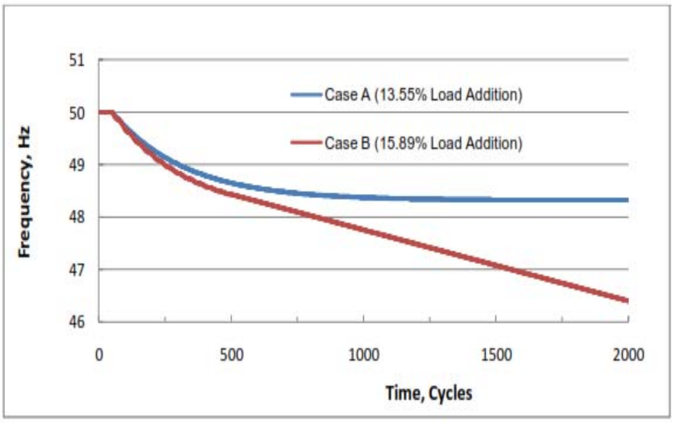

Fig. 3. Frequency response of Dhaka Island for load addition

Fig. 4. shows the fall of frequency in Dhaka region (island) in case of generation loss when no relay is being activated to shed load; case A refers system frequency remains within an accepted range up to a generation loss of 12.00% (252 MW) whereas case B refers the situation when 17.59% (369 MW) generation loss occurred to the system which makes the system unstable as the system frequency goes below the accepted range.

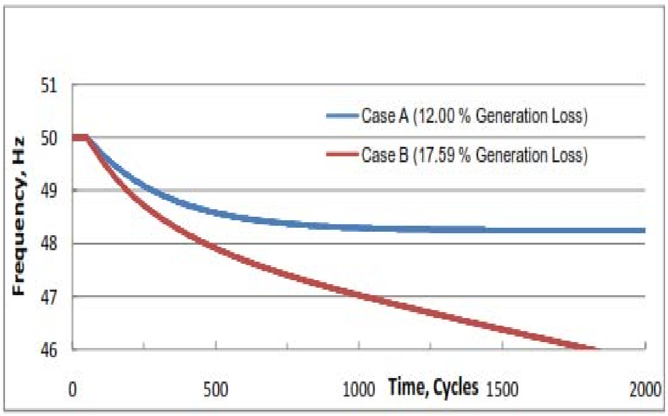

Fig. 4. Frequency response of Dhaka Island for generation loss

The simulated result for Khulna-Barisal region is shown in fig. 5.and fig. 6. Fig. 5 shows the fall of frequency in Khulna-Barisal region (island) in case of load addition when no relay has been activated to shed load; case A refers system frequency remains within accepted range up to 11.74% (71 MW) load addition whereas case B refers in case of 15.89 % (96 MW) load addition the system frequency goes below the accepted range making the system unstable.

The fig. 6. shows the fall of frequency in Khulna-Barisal region (island) in case of generation loss when no relay is being activated to shed the connected load; case A refers system frequency remains within accepted range up to a generation loss of 11.69% (71 MW) whereas case B refers in case of 17.50% (106 MW) generation loss the system frequency goes below the accepted range and makes the system unstable.

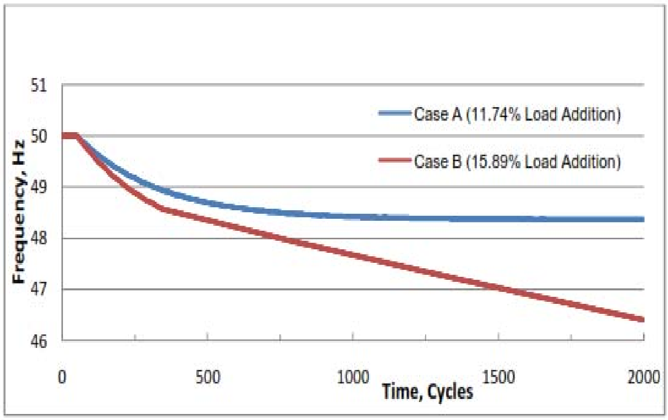

Fig. 5. Frequency response of Khulna-Barisal Island for load addition

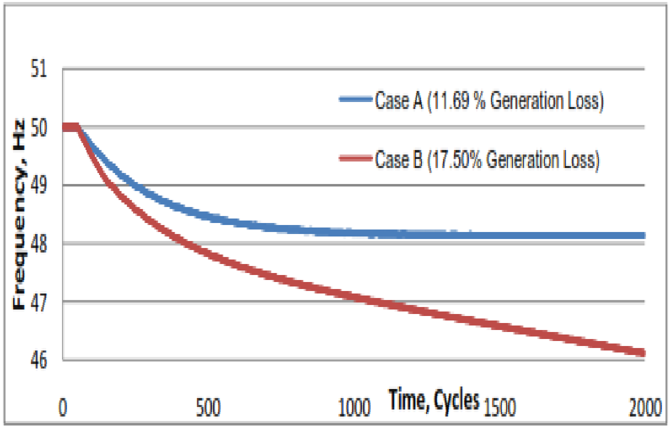

Fig. 6. Frequency response of Khulna-Barisal Island for generation loss

The impacts are compared in fig. 7.and fig. 8. Fig. 7 shows without activating any relay based load shedding 13.55% (284 MW) loads can be added to Dhaka region (Case A) where the percentage of load addition for Khulana-Barisal region (Case B) is 11.74% (71 MW). The result refers the larger islands can be operated in stable condition for larger percentage of sudden load addition.

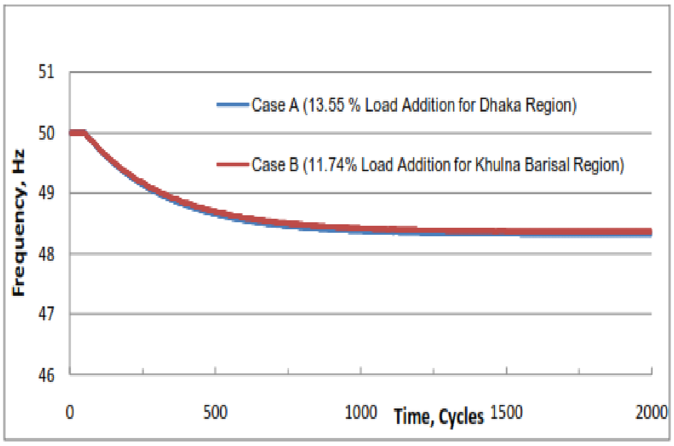

Fig. 7. Load addition comparison for different sizes of island without activating any relay

The fig. 8. shows without activating relay the Dhaka region (Case A) can be operated within acceptable frequency when 12.00% (252 MW) are forced to be shut down where the percentage of generation outages for Khulana-Barisal region (Case B) for system operation in acceptable frequency range is 11.69%(71 MW). It is observed from the result that larger islands can operate in stable condition for larger percentage of generation outages than smaller island.

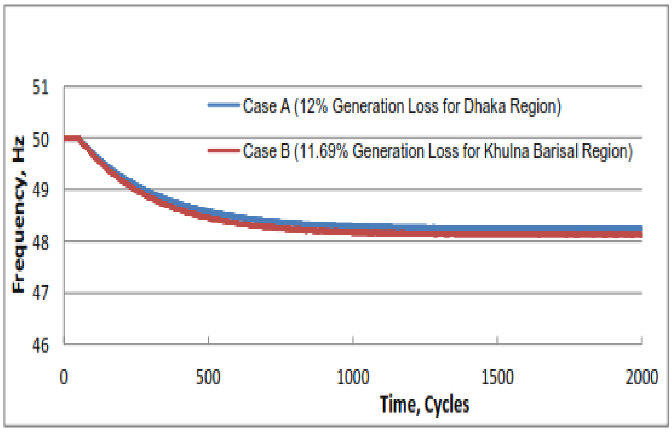

Fig. 8. Generation loss comparison for different sizes of island without activating any relay

IV. CONCLUSION AND FUTURE DIRECTIONS

Disturbances in an interconnected power system lead to frequency deviations in the grid but power system stability is dependent on the system inertial response. Based on the simulated results of the study and practical facts presented in this paper, it is clear that the system frequency stability is very much dependent on the overall H constant of the system. System with higher inertia constant shows more stability than system with relatively lower inertia constant. The addition or installation of machines with higher inertia constant makes the system more stable in case of any physical disturbances. In the close recovery it was evident that the rate of change of frequency and frequency drop decreases with addition of machines with high inertia constant. Frequency based auto load shedding scheme may be applied to different types/sizes of islands to observe the system dependency of inertia constant with a view to develop a principle of impacts of sizes of islands on the stability of faulted systems.

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