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On estimation of rate of change of frequency for relay settings during power export to grid from a CPP

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Amendments in the Indian Electricity Act in 2003, has opened up the Power Industry to make profitable business. Further, the acute shortage of power in India, can only be addressed by increasing the power generation and allowing smaller capacity distributed generation systems to interconnect to the grid. A captive power plant (CPP) associated with the fertilizer manufacturing sector is contemplating pumping its spare generation to the grid. This requires a study and settings of relays for protection of equipment associated with the CPP. On connecting to the grid the faults within the network may lead to either overloading or over speeding up of CPP generators. This requires a protective mechanism to isolate and island. This in turn is possible using quick response relays which are based on change in frequency or changes in load angle. By studying the related machine and system parameters, the effort is made to evolve the settings of such frequency based relay for the CPP under study. Using the swing equation as the basis along with related system parameters of the CPP and grid, the process of evolving the settings of Rate of Change of Frequency (RoCoF) and Vector Surge Relay (VSR) is discussed in this paper.

Keywords: *Captive power plant; Grid connection; Loss of mains; Frequency; Rate of change of frequency; Power export; RoCoF relay; Relay settings; Voltage surge relay*

1.0 INTRODUCTION

A strong power system network is essential to any country for its development. Though the pre-2003 scenario of Indian Power System network had a capacity of 100,000 MW of generation, the frequency varied by almost 3 Hz [1]. Such a huge variation in frequency has a long term detrimental effect on the steam turbines. During peak load hours, generating stations have to generate more and maintain the grid frequency at or closer to nominal. Also, during the low load hours, these generating stations have to abstain from pumping power so as to maintain the frequency. State Electricity Boards (SEBs) during the peak hours used to over-draw power and would compensate the same during off-peak hours by under drawing.

This kept the monthly energy consumption of the SEBs within the scheduled limits. This was not encouraging the generating stations to maintain the grid stability. The amendments in the Indian Electricity Act, 2003, managed to convert the vertically integrated monopoly structure to horizontal structure allowing private and public power generating companies to pump power to the grid by executing short/long term Power Purchase Agreements (PPA) with the SEBs or Distribution Companies (DisComs). In addition to this the single part tariff was replaced with a more business friendly tariff system, the three

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part or Availability Based Tariff (ABT) system in 2002. Bottlenecks pertinent to power exchange has been resolved with the effect of ABT. This has invariably encouraged many Captive Power Plants/Co-generation units to enter into short term PPAs (bi-lateral trade agreements) with the DisComs or with private power customers [2]. Some industries draw power from DisComs at a huge price and thus try to move for cheaper options.

Long term and short term power purchase agreements help the states in facilitating the development activities. These agreements, utmost, end up in a 'Win - Win' situation for all the stakeholders. This has been possible due to the introduction of ABT. Interconnecting of small distributed generation systems to the grid needs understanding of system dynamics, which has to be translated into protective mechanisms for isolating under system related issues. A transmission grid which is energized by various generation systems is expected to possess large amount of kinetic energy. However, a smaller capacity generation system has less kinetic energy and thus is expected to undergo frequency and load angle variations during loading, off-loading and faults. Protection relays which can detect such variations are employed to protect the generator and the grid.

The electrical equipment such as generators and transformers are expensive and vital for the operation of the power plant. In case of a CPP the health of these machines is vital for the output of such process-plants. The equipment which are connected to the grid during power export are used to operate the plant during the stages of plant operation which forms their core business. Thus investment on effective protection systems is inevitable. Loss of generation, overload and short circuit faults in the grid will lead to frequency changes in the CPP. These situations may lead to overloading of CPP and they are to be detected and CPP need to island resulting in forced isolation. Relays which trip based on Under- Voltage, Over-Voltage, Under-Frequency, Over-Frequency stand as the first line of defense [3]. Typically, an islanding situation should be detected within 200 to 300 ms (10 to 15 cycles), to avoid damage to loads and generators connected to the system [4]. The Rate of Change of Frequency (RoCoF) relays detect the islanding within 200 ms. These relays use a rolling average technique to measure the frequency and subsequently calculate the rate of change in frequency, enabling a faster detection time. Vector Surge Relays (VSR) also operate on a similar principle detecting the variation in rotor angle which directly affects the stability of the system. VSR are much faster compared to RoCoF relays as the zero crossing deviation is averaged only for 3 to 5 cycles. Faults due to lightning strike may cause loss of mains for short amount of time and return to normalcy. During this process, synchronized system gets islanded temporarily and tries to reconnect in a desynchronized manner. This causes voltage surges and load angle (δ) variations. There is a chance of generator loosing stability. Vector Surge and RoCoF Relays have proved to be efficient in detecting such situations and disconnects the Power Plant from the Grid almost instantaneously.

This paper focuses on a systematic approach to estimate the settings of RoCoF relay and VSR generally used in protection of a system from the grid abnormalities. This has reference to the protective like "MRG2 Woodward-SEG" [5].

2.0 CPP AND GRID CONNECTION

The CPP under study is equipped with eight generators driven by diesel engines, six of which are capable of running on both liquid fuel such as diesel and furnace oil or natural gas. The engines of the dual fuel (DF) sets are rated with an electrical output of 10.9 MVA at 11 kV each. The other two of different make having different inertial constants generally work as standby units. Hence the present study is only with reference to six DF generators.

The plant is designed with a dual bus bar system which are identified as Plant bus and Grid bus. Each DG has a provision to connect to either of the buses. A bus coupler arrangement is provided to keep the buses coupled or isolated, according to the requirement. Feeders are tapped from these buses which energize the process plant and power the auxiliary systems of the CPP. The CPP has provision to connect with Karnataka Power Transmission Corporation Ltd. (KPTCL) at 110 kV level. Two transformers of 32/40MVA capacity, 110/11kV, YNyn0D with OLTC connect KPTCL and CPP. The power can be exported to the grid through one of the bus system with an exclusive transformer. During such an arrangement the process plant remains not connected to the grid. A schematic of the CPP and Grid connection under study is represented in Fig.1. The schematic explains the locations of possible loss of generation causing disturbance (fault) and various cases that result from it. These cases are considered for the study in the following sections.

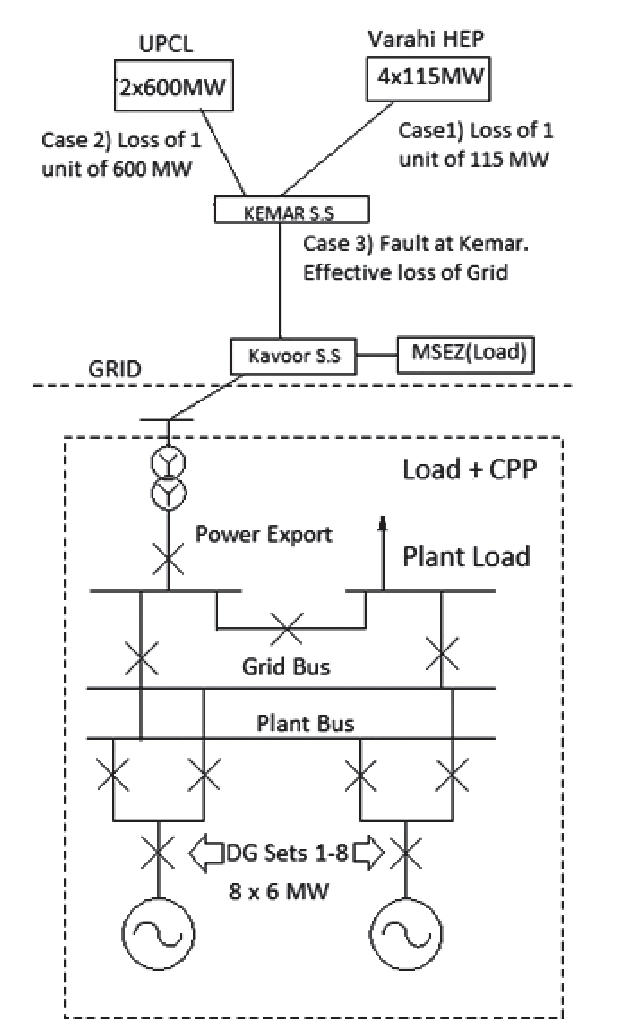

FIG.1. SCHEMATIC OF CPP AND GRID (WITH NEARBY GENERATING STATIONS FEEDING THE MAIN RECEIVING STATION CONNECTED TO THE SUBSTATION SYNCHRONIZING WITH CPP).

3.0 ESTIMATION OF RATE OF CHANGE OF FREQUENCY

When a generator is connected to the grid, the grid determines the frequency of operation and voltage at the Point of Common Coupling (PCC). The grid which has huge kinetic energy is unlikely to get disturbed during and post fault period. However, the dynamics of the generators and the system are to be understood for protecting the CPP.

A single-machine-infinite-bus system is considered for the analysis. It is assumed that the CPP generators (as a single unit or machine) pump power P_g into the system and the grid (infinite bus) consumes P_{sys}. When P_g is equal to P_{sys}, the frequency of the system remains constant. However, when the grid either looses part of its load or some of its generation, the system frequency changes. The rate of change of frequency is determined by the equation of motion (the swing equation). In case of such a situation the frequency swing can be attributed to the release of kinetic energy into the system by all rotating machines such as generators and motors. Every rotating machine which possess inertia (or kinetic energy) contributes to the swing in frequency. The swing in frequency is recorded as the rate of change of frequency (Equation (1) is used to determine the variation in frequency $(\frac{df}{dt})$.

Equation (1) is used to determine the variation in frequency as $\frac{df}{dt}$ [6].

$$\Delta P = \frac{P_G - P_L}{P_G} = \frac{2H}{f_0} * \frac{df}{dt} + D\Delta f \qquad ...(1)$$

where,

$\frac{df}{dt}$ refers to the Rate of Change of Frequency, in Hz/s.

P_G refers to the Power generated prior to the disturbance, in MW.

P_L refers to the Power generated after the disturbance, in

f_0 refers to the nominal frequency, in Hz MW.
H, Inertia constant, in seconds.

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D, Damping Coefficient of the load and generator, in p.u

MW/Hz.

Δf refers to the change in frequency from prior to after the disturbance in Hz.

Equation (1) can be simplified by ignoring the effect of damping in the system. Such an assumption would give the rate of change of frequency higher than the actual (worse case) from the frequency swing point of view. In other words, the obtained from (2) is greater than that seen in reality.

$$\frac{df}{dt} = \frac{f_0(P_G - P_L)}{2HP_G} \quad ...(2)$$

A. Estimation of equivalent inertia constant

The inertia constant of the generator is 1.15 s referred on its rated capacity of 10.9 MVA. When sources with certain inertia constants referred on its base MVA are paralleled, then an equivalent inertia constant has to be determined. The equivalent inertia constant is obtained using (3).

$$H_{eq} = \frac{\sum_{i=1}^{n} H_i G_i}{\sum_{i=1}^{n} G_i} \quad ...(3)$$

where,

G_i is the rated or base MVA of the i^{th} machine

H_i is the inertia constant of the i^{th} machine referred to its MVA (Gi)

H_{eq} is the equivalent inertia constant of the system,

n is the number of generators interconnected.

When identical machines are paralleled, the equivalent inertia constant turns out to be 1.15 s on the new base MVA. The CPP is connected to 220/110 kV Substation at Kavoor (a major substation supplying Mangalore). Kavoor substation receives power from Kemar through a 220 kV double circuit line. UPCL thermal power plant and Varahi Hydroelectric power (HEP) plant are two major power plants feeding Kemar substation which are considered for the present system study. UPCL and Varahi HEP have a rated capacity of 1200 MW and 460 MW, respectively. Inertia constants of thermal and hydroelectric power plants are assumed to be 3.2 s and 3.5 s, respectively. Using (3) along with the relevant data obtained from Karnataka Electricity Regulatory Commission (KERC) and Karnataka Power Map the inertia constant of the grid is found to be 3.19 s at 27179 MVA. This includes Central Generating Stations and all HEPs. Any rotating machine which stores kinetic energy contributes to the inertia in the system. Induction motors coupled with mechanical loads contribute to the inertia. Further, a change in the frequency causes the load on the generators to change. This is due to the load characteristics of the induction motors which are frequency dependent. If a loss of generation is considered to cause a rate of change (reduction) of frequency, the rate of decrease of frequency starts to reduce as induction motors starts to shed the load and eventually brings it to a steady state with certain amount of improvement in frequency. Thus, induction motor load gives a certain amount of damping effect towards frequency changes. The inertia constant of the system can be estimated if rate of change of frequency data is available during and post fault conditions.

4.0 ESTIMATION OF $\frac{df}{dt}$ SETTINGS FOR ROCOF RELAY

Three cases depicted in Fig.1 are considered in estimating the $\frac{df}{dt}$ involving CPP connected with grid. The calculations are performed assuming a power generation of 9000 MW meeting (the total demand from the grid. These cases are:

Case 1): When the CPP is connected to grid, and one unit of HEP at Varahi trips resulting in a loss of 115 MW from the grid. Here the ΔP is 115 MW.

Case 2): When the CPP is connected to grid, and one unit of thermal plant of UPCL trips resulting in a loss of 600 MW. Here the ΔP is 600 MW.

***Case 3*)**: When a fault at Kemar S.S causes overloading of CPP units. This is case of total loss of generation from the grid with loads downstream to the Kemar staying connected.

A. Estimating df/dt for Case 1):

A 115 MW (P_G-P_L) loss in generation corresponds to a regulation of $\Delta P = \frac{115}{9000}$ = 0.0128 p.u. Then (2) would result into

$$\frac{df}{dt} = 50(\frac{0.0128}{2*3.19}) \quad ...(4)$$

$$\frac{df}{dt} = 0.1\ Hz/s \quad ...(5)$$

The minimum value that can be set in the RoCoF relay is 0.1 Hz/s. This implies that a loss of 115 MW at Varahi HEP would result into change in frequency which does not concern operations of CPP. A setting of 0.1 Hz/s would make the CPP very sensitive to frequency drop causing nuisance trip. However, a 0.1 Hz/s setting along with a frequency supervision ($f+\frac{df}{dt}$) which is possible in certain relays would make the system more efficient.

B. Estimating df/dt for Case 2):

A 600 MW (P_G-P_L) loss in generation corresponds to a regulation of $\Delta P = \frac{600}{9000}$ = 0.067 p.u.

Then (2) would result into (6)

$$\frac{df}{dt} = 50(\frac{0.067}{2*3.19}) \quad ...(6)$$

$$\frac{df}{dt} = 0.52\ Hz/s \quad ...(7)$$

A roll off in frequency at a rate of 0.52 Hz/s would affect the operation of frequency dependent loads connected to the system. When CPP is interconnected with the grid, the generators will be working in kW mode with the loading fixed. During this mode the frequency is allowed to change within a band. If the rate at which the frequency varies or if frequency varies beyond the band, the generator switches to speed droop mode. Such a frequency variation can trigger the governor in CPP to act to maintain the nominal frequency (50 Hz), in speed droop mode. In such a scenario, it is possible to calculate ΔP on each generator, having estimated the rate of frequency change. Thus, (8) & (9) indicate that a 0.024 p.u (or 0.12 MW) load per generator would be the additional load on CPP (this is assuming a load of 5 MW on each generator at the time of disturbance).

$$\Delta P = 2 * \frac{1.15}{50} * \frac{df}{dt} \quad ...(8)$$

$$\Delta P = 0.024\ p.u \quad ...(9)$$

C. Estimating df/dt for Case 3):

A fault at Kemar substation results in loss of mains as seen from the CPP as a far end fault. This is one of the most probable worst case situation that may occur. In this case, the CPP is overloaded with Kemar's downstream load connected to the substation, as it could be the only healthy generating station. But, it can be safely assumed that the load on the CPP will be more than its generating capacity. This implies, if each generator was pumping 5 MW into the system, its maximum de-rated capacity being 6 MW restricts the governor from loading more. Thus a limiting case of 0.17 p.u of load regulation on the generator can be assumed. As the grid is effectively lost, the inertia of the rest of the system is dictated by the synchronous generators of CPP that are available. Thus the inertia constant of the system (CPP alone) has to be considered (H=1.15 s).

$$\frac{df}{dt} = 50(\frac{0.17}{2*1.15}) \quad ...(10)$$

$$\frac{df}{dt} = 3.7\ Hz/s \quad ...(11)$$

A fault at the Kemar substation (effect of loss of total generation from the grid) would certainly load the CPP generators more than this case. Thus it is certain that the rate of change of frequency is greater than 3.7 Hz/s in actuality. Adopting a setting less than this (< 3.7 Hz/s) would be prudent. A frequency supervision ($f+\frac{df}{dt}$)

which is possible in certain relays would make the system more efficient.

5.0 SETTINGS FOR VECTOR SURGE RELAY

VSR also uses the same principle of Zero Crossing Detection as in RoCoF relay. However, the parameter sensed here is the phase angle difference (shift in zero crossing of the voltage wave with respect to zero crossing of the voltage wave under unperturbed condition). It implies, the shift in the voltage phasor is sensed. This fact can be supported with an 2*3.19 explanation of variation in reactance during and after a short circuit fault. During a fault, as the reactance increases and thus the electric power output (P_e) drops down to a lower value, with power supplied by the prime-mover remaining the same, causes increase in the rotor angle (δ)[7]. It is not advisable to operate the machine at higher δ values, as it may lead the system into instability for even small disturbances. The variation in δ causes the frequency variation in the voltage phasors [7]. If the fault is at far end, say at Kemar substation then the load connected to the substation immediately get transferred to the CPP. This will affect the generator and may lead to very high frequency drop. The load angle or the angle between the rotor and the stator fields will increase which may lead to unstable operation of the system. A Short Circuit type loading of the alternators take place during distant mains failure. This is the case 3 discussed under RoCoF relay.

As seen from the literature [4] no straight forward approach has been established to obtain the settings for the VS Relay. A high impedance main is generally set with values between 10 to 12 degrees and a low impedance mains without auto-reclosing is set with 5-8 degrees [5]. Based on the present study related to the RoCoF relay settings, an equi-spaced linear scaling of the ranges can be used to establish a relation between RoCoF relay with that of VSR. The RoCoF relays are available from a range of 0.2 Hz/s (or 0.1 Hz/s) to 10 Hz/s and VSRs are available with a range of 2 to 22 degrees. With the assumption that the two extremes of the relay setting range in both relays coincide, an equi-spaced scaling (0.2 Hz/s: 10 Hz/s :: 2º : 22º), with 10 divisions would set a precision of 0.98 Hz/s corresponding to 2 degrees. Thus a 3.7 Hz/s setting of RoCoF relay would correspond to a phase angle difference of 9.5º. This can be obtained using the nomogram shown in Fig.2. Thus 9.5º would be the setting of VSR for this case study.

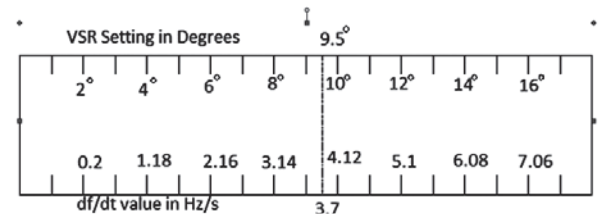

FIG.2 NOMOGRAM REPRESENTATION FOR VSR SETTINGS

6.0 CONCLUSION

By studying the related machine and system parameters, of a CPP and associated grid, an effort has been made to estimate the $\frac{df}{dt}$ for few likely cases of occurrences (faults) which would help in deciding the RoCoF relay setting.

Based on the few likely cases of occurrences (faults) in the grid, the estimated $\frac{df}{dt}$ settings for RoCoF relay for the grid connected CPP is < 3.7 Hz/s. This is only suggestive and may need further study.

In estimating the settings for a Vector Surge Relay (not being straight forward) the RoCoF relay setting is used by linear mapping over their ranges of settings.

These results need further study and field testing in real time operations.

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