A Coherency Based Generation Rescheduling for Improving the Dynamic Security of Power Systems

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Abstract

In this paper, a preventive control method against transient instabilities due to a set of critical contingencies that could occur in a large power system is proposed. The generation rescheduling, adopted as the preventive control, is based on the coherency between the generators. The rescheduling is done by attempting to bring the generators' rotor speeds equal after a three phase fault that might cause instability. The proposed methodology involves offline simulations to determine the system response and calculation of the critical clearing time for each contingency. Whereas the rescheduling method is based on the severity of each contingency, it improves and aims to restore the system's stability for all contingencies that are taken into account.

1. Introduction

The purpose behind dynamic security analysis studies is to check the ability of the power system to withstand against different contingencies, and to survive the transient stage of the contingency passing to acceptable steady-state operation conditions [1]. Dynamic security analysis gives indications about the remedial actions when necessary. Preventive control is preferred to improve the system security in the case of detecting any potential instability caused by severe contingencies especially for the systems running near their stability limits [2]. A severe contingency means that the critical clearing time (CCT) is smaller than the actual operating time of circuit breakers in the power system. The purpose of the preventive control is to make all CCTs longer than the circuit breaker operating times [3].

Generation rescheduling is considered as one of the most favorable preventive control method for improving the power system transient stability in the face of potential instable contingencies, even though it have a high cost [4]. The major issues of generation rescheduling are determination of the amount of generation change and the choice of generators. A variety of preventive generation rescheduling methods have been proposed in the literature. Sensitivity approaches based on transient energy function (TEF) methods [1], [2], [6], decision tree based method [5], the single machine equivalent (SIME) method [3], coherency identification [7], [8], extended equal area criterion [9], trajectory simulation [10], and artificial neural network techniques [11] have been developed for evaluating preventive actions.

In this paper an extended work based on the method in [7]. The method, which based on coherent behavior of generators, is proposed for improving the dynamic security of the power system. The idea of coherent behavior of generators is used to find a new generation schedule with better transient stability behavior. This dynamic security dispatch is based on the idea that increasing coherency between the generators at the fault clearing time makes the system more dynamically secure [7], [8]. Generation rescheduling is proposed by moving the generators so that, at the time of fault clearing, the rates of change of speed for all the generators are brought closer. The calculations in the proposed method include the original generation, the generators post-fault rotor speed trajectory after the clearing time of the fault, and the inertia constants of the generators. The original method in [7] is applied on the power system for a specified critical contingency. In this paper, the previous mentioned method is extended to simulate a set of critical contingencies at the same time. For each critical contingency the critical clearing time is calculated, then this critical clearing time is used to define a new scaling factor. For each critical contingency, the rotor speed trajectory is calculated and then multiplied with the scaling factor. The scaling factor is depending on the severity of the critical contingencies, the more severe contingency, the bigger scaling factor is used, and vice versa. The new generation schedule will fortify the power system against all the unstable critical contingencies.

For analyzing the dynamic security of the system, specifying the severe contingencies, and the efficiency of the new generation schedule, a simulation package DSATools™ [13] was used. The contingencies were three phase faults with one line outages for clearing the faults. The method has been tested on the test system consisting of 68-bus 16-generator. This test system is a much less detailed model of the U.S. Northeastern and Ontario system.

2. System Equations

The For an n-generators power system, the classical second order dynamic model of the i-th generator with respect to center of inertia (COI) reference frame can be described as follows [6], [7]

$$M_i \dot{\widetilde{\omega_i}} = P_{m_i} - P_{e_i} - M_i \left(\frac{P_{COI}}{M_T}\right) \tag{1}$$

$$\dot{\theta_i} = \widetilde{\omega_i} \qquad i = 1,2,\dots,n \tag{2}$$

where,

$$P_{e_i} = \sum_{j=1}^{n} E_i\, E_j \left[B_{ij}\sin(\delta_{ij}) + G_{ij}\cos(\delta_{ij})\right]$$

$$P_{COI} = M_T\, \dot{\omega}_0 = \sum_{i=1}^{n} \left(P_{m_i} - P_{e_i}\right)$$

$$M_T = \sum_{i=1}^{n} M_i$$

And for each generator i

G_{ij} and B_{ij} are the conductance and suspectance of the (i,j)-th entry of the bus admittance matrix of the power system $\mathbf{Y_{bus}}$ [14].
P_{m_i} : Mechanical power input
E_i : Constant voltage behind transient reactance
M_i : Inertia constant of generator
θ_i , $\widetilde{\omega_i}$: Electrical angle and speed of machine with respect to COI reference frame.

The purpose of generation rescheduling is to improve the dynamic security of the power system by finding a new generation schedule with better transient stability behavior than the original generation schedule. For the cases of severe contingencies with unstable transient response, the generation rescheduling is applied, in such a way that the power system will have a stable response for the new generation schedule, while unstable response for the old generation schedule. This will increase the dynamic security of the power system against the severe contingencies.

The assumptions were taken in consideration for simplification in [7], to be able to apply the proposed method are listed below:

I. During the time from the pre-fault steady equilibrium point to the fault clearing time t_{cl}, the change rate of each rotor speed with respect to time is considered constant.
II. During the rescheduling the loads are considered not changing; P_{L_i} =constant, $i = 1,2,\dots,n_L$ (n_L is the number of loads).
III. Total generation capacity are considered not changing to equal the not-changing total load in the system; $\sum P_{m_i} =$ constant, $i = 1,2,\dots,n$

Equation (1) is rewritten in the form

$$M_i\,\dot{\widetilde{\omega_i}} = P_{m_i} - P_{D_i} \qquad i = 1,2,\dots,n \tag{3}$$

where,

$$P_{D_i} = P_{e_i} + M_i\left(\frac{P_{COI}}{M_T}\right)$$

To distinguish the generation schedules; for the old generation schedule "old" subscript is used, while the "new" subscript is used for the new generation schedule after applying the proposed method of generation rescheduling. From equation (3) we have the new equations (4) for the old schedule, and (5) for the new schedule:

$$M_i\,\dot{\widetilde{\omega}}_{i_{old}} = P_{m_{i_{old}}} - P_{D_{i_{old}}} \qquad i = 1,2,\dots,n \tag{4}$$
$$M_i\,\dot{\widetilde{\omega}}_{i_{new}} = P_{m_{i_{new}}} - P_{D_{i_{new}}} \qquad i = 1,2,\dots,n \tag{5}$$

Subtracting (4) from (5):

$$\begin{aligned} M_i\left(\dot{\widetilde{\omega}}_{i_{new}} - \dot{\widetilde{\omega}}_{i_{old}}\right) &= \left(P_{m_{i_{new}}} - P_{m_{i_{old}}}\right) \\ &- \left(P_{D_{i_{new}}} - P_{D_{i_{old}}}\right) \end{aligned} \tag{6}$$

From previous assumption (I) and (II), the change rate of the rotor with respect to time is considered to be constant, which yields the neglecting of the term $\left(P_{D_{i_{new}}} - P_{D_{i_{old}}}\right)$ in equation (6). Equation (6) is rewritten as follows,

$$M_i\left(\frac{\widetilde{\omega_i}_{\,new} - \widetilde{\omega_i}^{\,sep}_{\,new}}{t_{cl}} - \frac{\widetilde{\omega_i}_{\,old} - \widetilde{\omega_i}^{\,sep}_{\,old}}{t_{cl}}\right) = \left(P_{m_{i_{new}}} - P_{m_{i_{old}}}\right)$$

or

$$M_i\left(D_{wi_{new}} - D_{wi_{old}}\right) = \left(P_{m_{i_{new}}} - P_{m_{i_{old}}}\right) \tag{7}$$

Where; the phrase "sep" represents the post-fault stable equilibrium point,
$\widetilde{\omega_i}^{\,sep}_{\,new} = \widetilde{\omega_i}^{\,sep}_{\,old} = 0$;
$D_{wi_{new}} = \dfrac{\widetilde{\omega_i}_{\,new}}{t_{cl}}$;
$D_{wi_{old}} = \dfrac{\widetilde{\omega_i}_{\,old}}{t_{cl}}$

The proposed method aims to find the new generation capacities $P_{m_{i_{new}}}$, in such a way that all the machines have the same rate of change in the rotor speed after the generation rescheduling. In another words; $D_{w1_{new}} = D_{w2_{new}} = \cdots = D_{wn_{new}}$.

For a single critical contingency, from equation (7) for n-generators we have:

$$\sum_{i=1}^{n} M_i\,D_{wi_{new}} - \sum_{i=1}^{n} M_i\,D_{wi_{old}} = \sum_{i=1}^{n} P_{m_{i_{new}}} - \sum_{i=1}^{n} P_{m_{i_{old}}} \tag{8}$$

From assumption (III) we have

$$\sum_{i=1}^{n} P_{m_{i_{new}}} = \sum_{i=1}^{n} P_{m_{i_{old}}} \tag{9}$$

According to equation (7), (8) and (9), and since $D_{w1_{new}} = D_{w2_{new}} = \cdots = D_{wn_{new}}$, we have:

$$P_{m_{1_{new}}} = \frac{P_{m_{1_{old}}} \times A + \sum_{i=2}^{n} M_i\left(D_{wi_{old}} - D_{w1_{old}}\right)}{A} \tag{10}$$

$$\begin{aligned} P_{m_{i_{new}}} = \frac{M_i}{M_1}P_{m_{1_{new}}} - \frac{M_i}{M_1}P_{m_{1_{old}}} - M_i\left(D_{wi_{old}} - D_{w1_{old}}\right) \\ + P_{m_{i_{old}}} \end{aligned} \tag{11}$$

where,

$$A = \left(1 + \frac{1}{M_1}\sum_{i=2}^{n} M_i\right)$$

Equations (10) and (11) are used to specify the new generation schedule for preventing the power system potential instability caused by a single contingency. For a set of critical contingencies with critical clearing time (CCT) for each, equations (10), and (11) can be modified to build a new generation schedule that able to prevent the system potential instability for all the critical contingencies in the specified set. For each critical contingency, a new scaling factor $\left(C_j\right)$ is defined. The rotor speed trajectory $\left(D_{wi_{old}}\right)$ for each critical contingency is multiplied with the scaling factor, in such a way that, the more severe contingency is having bigger scaling factor than the less severe contingency. For m-critical contingencies, the new generation schedule can be found as follows

$$P_{m_{1_{new}}} = \frac{P_{m_{1_{old}}} \times A + \left(\sum_{j=1}^{m}\sum_{i=2}^{n} M_i\left(C_j D_{wi_{old}} - C_1 D_{w1_{old}}\right)\right)\Big/ m}{A} \tag{12}$$

$$P_{m_{i_{new}}} = P_{m_{i_{old}}} + \frac{M_i}{M_1}P_{m_{1_{new}}} - \frac{M_i}{M_1}P_{m_{1_{old}}} - \left(M_i \textstyle\sum_{j=1}^{m}\left(C_j D_{wi_{old}} - C_1 D_{w1_{old}}\right)\right)\Big/ m \tag{13}$$

where,

$$A = \left(1 + \frac{1}{M_1}\sum_{i=2}^{n} M_i\right)$$

With the equations in (12) and (13), the new generation schedule can be calculated, which will assure that the generators will have the same rate of changing in the rotor speed after any critical contingency from a specified set of critical contingencies.

3. Methodology

The methodology of the proposed preventive generation rescheduling algorithm is explained in this section. Computer program is used for specifying the potential critical contingencies which have CCT less than the clearing time of the circuit breakers. The original methodology explained in reference [7] is done to perform the rescheduling process one by one for each potential critical contingency. The proposed methodology is an extended version from the algorithm in [7] to perform the rescheduling process for all the potential critical contingencies at once. For each critical contingency the CCT is calculated, which is used to specify a new scaling factor (C_j). The value of the scaling factor depends on the severity of the critical contingencies, the smaller CCT, the bigger C_j . A checking process for the new operating point should be done, that after changing the operating point, a new contingency may become critical for the new operating point.

The goal of the algorithm is to find a new generation schedule in which it will be secure for all the possible contingencies while taking into consideration the assumptions (II) and (III). The methodology for this algorithm is explained as follows:

1. Use the simulation package for dynamic security analysis by considering three phase fault with single line outages, while taking into consideration assumptions (II) and (III).
2. Selecting the insecure contingencies according to the value of critical clearing time (CCT). The contingency with CCT value smaller than the actual operating time of circuit breakers is considered as insecure.
3. Calculate the scaling factors C_j , the smaller CCT, the bigger C_j. The scaling factor values are changing in the period [0.9 1.1].
4. Calculate the new generation schedule using equations (12) and (13).
5. Stop.

4. Simulation Results

For testing the methodology explained before, a test system consisting of 68-bus 16-generator was chosen. This test system is a much less detailed model of the U.S. Northeastern and Ontario system. In the 16-generator system, only the New England system is represented in detail with generators 1 to 9, while the neighboring utility systems in New York, Pennsylvania, Michigan and Ontario are modeled with large equivalent generators 10 to 16 [12]. The one line diagram of the test system is shown in Fig. 1.

At the beginning, a complete contingency scanning was done on the test system using a computer program to specify the set of potential critical contingencies which holds the assumptions (II) and (III) that means; the total loading and generation in the system do not change. A set of 128 possible contingencies was built. Then, the system with the original generation schedule was applied to this set of contingencies. The fault clearing time was chosen to be 5 cycles. The contingencies with CCT less than 5 cycles were taken as the critical contingencies between the 128 set of contingencies. The critical contingencies for the original generation schedule are listed in Table 1. Some of the critical contingencies are in the same line sides, and for that case, only one of these contingencies was considered into the calculation. The post-fault rotor speed trajectory for each critical contingency illustrated in Table 1 is calculated.

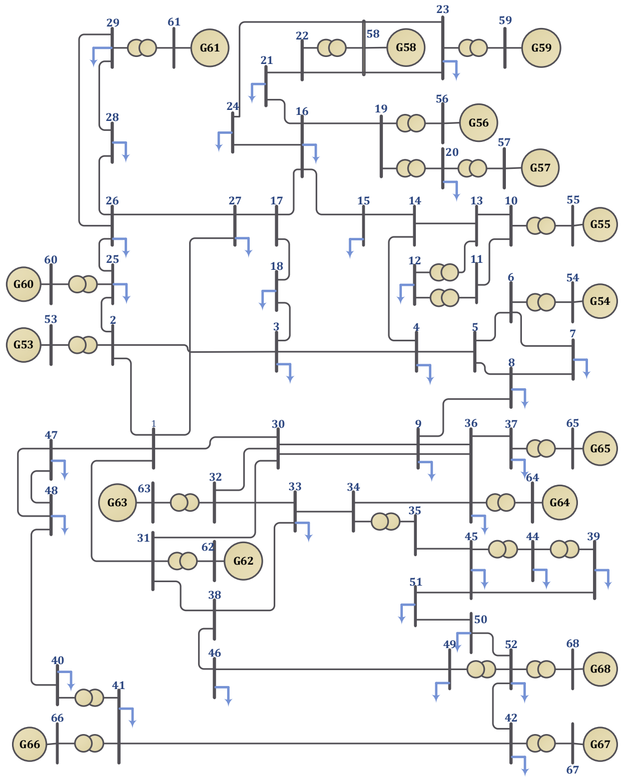

Fig. 1. One line diagram of the 16-generator 68-bus system

The scaling factors for each critical contingency can be calculated to be changing in the period [0.9 1.1], the smaller CCT, the bigger C_j, for example the first contingency have the smallest CCT with 0.5 cycle, a scaling factor with the value 1.1 was chosen for that contingency. The scaling factors for the set of critical contingencies is illustrated also in Table 1.

Equations (12), and (13) were used to specify the new generation schedule for the test power system, to fortify the test power against the potential set of contingencies illustrated in Table 1. The new generation schedule is illustrated in Table 2, and as it can be seen that the total amount of generation capacity is not changing before and after the rescheduling. The generation capacity of the accelerating generators was decreased in the new schedule, while for the decelerating generators, their generation capacity were increased.

For checking the accuracy of the proposed method, the same process of contingency scanning was done on the test power system with the new generation schedule. The previous set of critical contingencies illustrated in Table 1 were applied on the test power system and the new critical clearing time after the rescheduling process are illustrated in Table 3. As it can be seen from Table 3, the rescheduling process succeed to improve the dynamic security of the test power system, since all the CCT of the critical contingencies increased above the specified value of 5 cycles. In Table 3, sample of noncritical contingencies are illustrated to show that the new operating point did not change the dynamic security of the other contingencies.

Table 1. List of the potential critical contingencies for the test system with the scaling coefficients for each

No.	3-Phase Fault at Bus	Removing Line	CCT (cycle)	Scaling Factor C_j
1	52	50-52	0.5000	1.1000
2	51	50-51	0.5000	1.1000
3	51	45-51	0.5000	1.1000
4	40	48-40	0.5000	1.1000
5	40	41-40	0.5000	1.1000
6	52	49-52	4.2967	0.9258
7	29	28-29	4.5779	0.9129
8	22	21-22	4.8592	0.9000
9	29	26-29	4.8592	0.9000

Table 2. Generation rescheduling results after applying the proposed methodology

Generator No.	Old Generation Schedule (MW)	New Generation Schedule (MW)
1	250	367.90
2	545	459.55
3	650	547.08
4	632	665.89
5	505.2	526.54
6	700	681.54
7	560	541.81
8	540	581.97
9	800	539.34
10	500	411.25
11	1000	1014.4
12	1350	1692.6
13	3573	5505.7
14	1785	1256.5
15	1000	458.48
16	1000	1014.4

Table 3. Critical clearing time for some contingencies after applying the proposed methodology

No.	3-Phase Fault at Bus	Removing Line	Old CCT (cycle)	New CCT (cycle)
1	52	50-52	0.5000	19.6484
2	51	50-51	0.5000	30.0000
3	51	45-51	0.5000	30.0000
4	40	48-40	0.5000	30.0000
5	40	41-40	0.5000	30.0000
6	52	49-52	4.2967	21.6015
7	29	28-29	4.5779	11.0545
8	22	21-22	4.8592	5.5857
9	29	26-29	4.8592	11.0545
10	1	2-1	19.2577	24.5993
11	2	25-2	9.8827	9.8086
12	18	3-18	15.7421	17.6952
13	11	6-11	9.8827	13.3983
14	37	43-37	15.7421	13.0077
15	33	38-33	11.0545	11.4452
16	32	30-32	7.1483	7.5389

From Table 3, it can be noticed that the new generation schedule brought the system to a new operating point where it is secure for all the potential contingencies. From 128 total potential contingencies, there were 96 contingencies that had higher critical clearing time for the new generation schedule, only 6 contingencies that had higher critical clearing time for the original generation schedule but it still secure, the last 26 contingencies had the same critical clearing time for both generation schedules. In total, the new generation schedule secured the system against all the potential contingencies, also it increased the critical clearing time for most the other contingencies that made the system more protected even for the previously secure contingencies, in other words, the proposed method successfully improved the dynamic security of the system.

For showing the improvement on the dynamic security of the power system after applying the generation rescheduling, the first contingency in Table 1 was taken as example. Fig. 2 shows the power system response before generation rescheduling, while Fig. 3 shows the power system response after the generation rescheduling. As it can be seen from Fig. 2, and Fig. 3, the generation rescheduling was successful on improving the dynamic security of the power system.

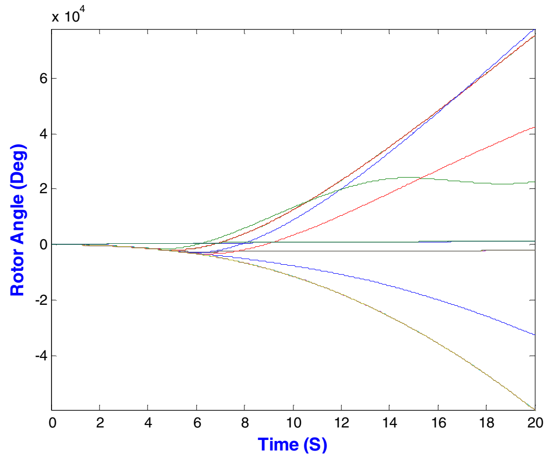

Fig. 2. Power system response for old generation schedule after contingency No. 1

5. Conclusions

The proposed preventive generation rescheduling method for enhancing the dynamic security of the power system has been successfully tested in this paper. The method is using the coherent behavior concept of generators to find a new generation schedule with better transient stability behavior. This dynamic security dispatch is based on the idea that increasing coherency between the generators at the fault clearing time makes the system more dynamically secure by making the rates of change of speed for all the generators closer. The calculations in the proposed method include the original generation, the generators post-fault rotor speed trajectory after the clearing time of the fault, and the inertia constants of the generators.

The proposed method uses the critical clearing time for the severe contingencies to define a new scaling factor. The scaling factor depends on the severity of the critical contingencies, the smaller CCT, the bigger scaling factor. This will allow the algorithm to process all the critical contingencies at once, which will increase the speed of the algorithm.

The proposed method was tested on a test power system successfully, and it was able to improve the dynamic security of the test power system, and fortify the power system against all the critical contingencies at once.

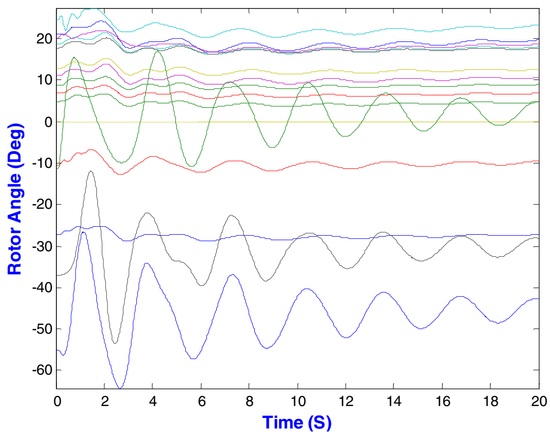

Fig. 3. Power system response for new generation schedule after contingency No. 1

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