A Novel Protective Scheme to Protect Small-Scale Synchronous Generators Against Transient Instability

Reza Razzaghi, Mahdi Davarpanah, and Majid Sanaye-Pasand, *Senior Member, IEEE*

***Abstract*—Installation of small generators in distribution networks has been increased recently due to its various benefits. One of the important issues related to these distributed generators is the effect of system faults on their transient stability. Due to the low inertia constant of the small-scale generators and the slow operation of the distribution networks' protective relays, transient instability is quite probable for these generators. In this paper, the dynamic behavior of small-scale synchronous generators to the system faults and its sensitivity to the system parameters are investigated. Then, a practical protective method using the existing overcurrent and undervoltage relays is proposed, and its advantages and disadvantages are pointed out. Next, based on the obtained information from sensitivity analysis, a novel protective relay is proposed to protect the generators against instability. The proposed relay uses a generator active power to determine the appropriate time to disconnect the generator. Simulation results confirm the secure operation and robustness of the proposed relay against system transients. In addition, the proposed algorithm complies with the generator fault-ride-through requirements.**

***Index Terms*—Distributed generation (DG) protection system, distributed generation, fault ride through (FRT), transient stability.**

I. Introduction

DISTRIBUTED GENERATION (DG) is defined as an electric power source connected directly to the distribution network of a power system [1]. Nowadays, the installation of DGs is increasing in power systems due to its benefits including loss reduction, peak shaving, ancillary services, higher power quality, their shorter build time, the lower loss of load probability as well as the deferral of transmission, distribution replacement, deregulation issues, and environmental concerns [2]–[5]. However, the interconnection of DGs imposes some changes to the existing distribution systems and can create an instability in the power systems, even leading to outages [6], [7]. When DG operates in parallel with the utility, the improvement of the traditional distribution system protective schemes and the utilization of proper relaying and setting for DG would be the most crucial requirements to prevent generator instability. DG protection system can be divided into two main sections: interconnection protection and DG unit relays [8]. Typically, the interconnection protection is installed at the point of common coupling (PCC) between the generator and the utility and provides the following functions [8]:

1) disconnecting the generator or PCC when DG is no longer operating in parallel with the utility system;
2) protecting the utility system from damages caused by the connection of the generator, including the fault current supplied from the generator to the system faults and transient overvoltages;
3) protecting the generator from damages which originate from the utility system.

DG protection provides the detection of the following:

1) generator internal short circuits;
2) abnormal operating conditions, e.g., loss of field, reverse power, overexcitation and unbalanced currents, and over/underspeed.

In addition, one of the important tasks of the DG protection relay is the detection of transient instability of the generator. Transient stability is defined as "the ability of the power system to maintain synchronism when subjected to a severe transient disturbance" [9]. Critical clearing time (CCT) is an important index related to the transient stability concept. It is defined as "the maximum time between the fault initiation and its clearing such that the power system is transiently stable" [10].

At present, most DG systems employ synchronous generators (SGs) [11]. The vast majority of the DGs which have been installed in our country are also SGs. Therefore, this paper is only focused on this type of generators, and the other types of resources such as renewable sources are not considered in this paper.

For an SG, there exists a maximum rotor angle below which SG can retain a stable operation. Fault clearing time and generator inertia have important effects on the stability of the SG. Fault clearing time for transmission system is about 100 ms. However, this time for distribution networks may become much longer. Moreover, the inertia constant of small-scale SGs (SSSGs) is typically low; usually, it is smaller than 2 s [11], in comparison with the inertia constant of about 3–5 s for large-scale SGs. Transient instability is an important concern for the large-scale generators. Considering the aforementioned points, transient instability becomes a more serious concern for SSSGs connected to the distribution networks. Therefore, in-depth studies must be performed to find out the dynamic behavior of these generators against the system faults.

The loss of synchronism condition for an operating generator is a very serious concern for the electrical and mechanical

Manuscript received May 6, 2011; revised December 12, 2011; accepted January 13, 2012. Date of publication February 3, 2012; date of current version November 22, 2012. This work was supported by the University of Tehran under Grant 8101064-1-03.

R. Razzaghi and M. Davarpanah are with the School of Electrical and Computer Engineering, College of Engineering, University of Tehran, Tehran 14395-515, Iran (e-mail: r.razzaghi@ut.ac.ir; m.davarpanah@ece.ut.ac.ir).

M. Sanaye-Pasand is with the School of Electrical and Computer Engineering, College of Engineering, University of Tehran, Tehran 14395-515, Iran, and also with the Control and Intelligent Processing Center of Excellence, School of Electrical and Computer Engineering, College of Engineering, University of Tehran, Tehran 14395-515, Iran (e-mail: msanaye@ut.ac.ir).

Digital Object Identifier 10.1109/TIE.2012.2186773

integrity of the SSSG and prime mover [12]. Serious damages can result due to this condition. Out-of-synchronism conditions also cause torque reversals that create, in many parts of the generator and prime mover system, high mechanical stresses of magnitudes that may be several times the system rated torque. These excessive torques may cause damage to the shaft of the generator or prime mover or actually cause the generator and/or prime mover to wrench free of the mountings to the foundations. Meanwhile, the loss of synchronism is primarily a risk to the generator and is not a serious danger for the system operation. Therefore, the transient stability of the generators is out of the scope of the standard IEEE 1547 [12].

To prevent transient stability problem for small-scale generators connected to the distribution networks, according to some existing grid codes [13], it is suggested to disconnect the DG units immediately after occurrence of a fault in the network. However, if DGs supply a significant share of the total load, extensive disconnections following the network faults will remarkably reduce the benefits expected from these energy sources. In addition, the sudden disconnection of a large block of DG could adversely affect the normal operation of the network and may result in voltage sag and overload for the network.

To prevent large unbalances between generation and load due to the disconnection of DG units, some grid operators have defined fault-ride-through (FRT) requirements. New grid codes oblige distributed power-generation systems to remain connected to the power network during the fault to avoid massive chain disconnections. The goal of the FRT requirements is to prevent the disconnection of an undesirable portion of power generation during an abnormal condition [14], [15].

The influence of a fault in the network on the stability of DGs is investigated in [16]. It indicates that the present setting of undervoltage (UV) relays [0.8 per unit (p.u.), 200 ms], which is utilized as a function of interconnection relays, might lead to the massive tripping of DG units over large areas in the case of short circuits at the transmission level. Therefore, an appropriate adjustment of the UV relay is necessary to comply with the FRT requirements.

In [17], the effect of grid protection on the stability of DG units is studied. It is shown that all DG units are disconnected by the UV protection before the fault is cleared by the related grid protective relays. Meanwhile, this protection is necessary in order to prevent instability and cannot be disabled.

The effect of the fault clearing time on the transient stability of the DGs is studied in [18]. It suggests performing transient stability analysis for distribution networks including DGs and adjusting protection settings to avoid the instability of DGs. In addition, it proposes that the DG UV relay setting should be determined based on the transient stability studies.

There are various techniques available in literature and in practice to detect out-of-step conditions, e.g., distance relay with blinders, neural networks, and fuzzy logic-based schemes [19]. This paper also proposes a new method to detect the out-of-step condition for the SG. The proposed method is based on the equal-area-criterion theory and uses generator active power to discriminate between stable and out-of step conditions.

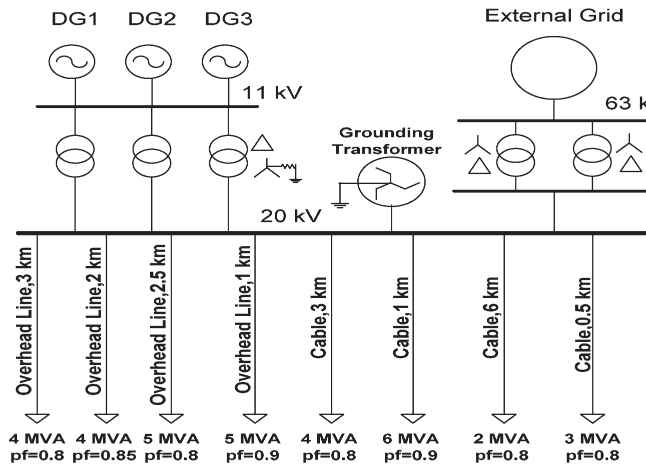

Fig. 1. System under study.

In this paper, to investigate the dynamic behavior of the SSSGs against system faults, the sensitivity of the CCT of the SSSGs to the system parameters will be discussed. Then, a proposed protection method using the existing relays based on the type of the outgoing feeders is investigated, and its weakness and problems are pointed out. Next, the obtained results are used to propose a novel algorithm to protect the generators against transient instability. The SSSG output active power during the fault and the CCT are used to extract the characteristic of the proposed relay.

The results comply with the SSSG units' FRT requirement, while at the same time, their safe operation is guaranteed. In addition, the proposed algorithm is robust against the changes in system configuration and has a secure operation during system disturbances.

II. Transient Stability of the SSSG

In this section, the dynamic behavior of the SSSG against system faults is analyzed. Then, the sensitivity analysis of the generator transient stability to the system parameters such as fault type, fault location, interconnection transformer impedance, generator prefault load, and control mode of the excitation system is investigated.

A. System Model

For this paper, a real 63/20-kV substation including three SSSGs is simulated using DIgSILENT Power Factory software. These generators are connected to the 20-kV bus bar using three interconnection transformers. The vector group of these transformers is grounded Wye (utility)–Delta (DG) which is an appropriate choice for an interconnection transformer [20]. Generator neutrals are grounded with a resistance to limit its single-phase-to-ground fault current. Outgoing feeders include both overhead lines and cables to be able to study all possible conditions. The 63-kV network is modeled by its Thevenin equivalent as the external grid. The studied system is shown in Fig. 1 whose electrical parameters are presented in the Appendix.

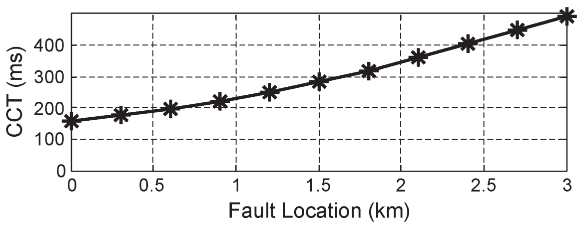

Fig. 2. CCT versus fault location for three-phase faults.

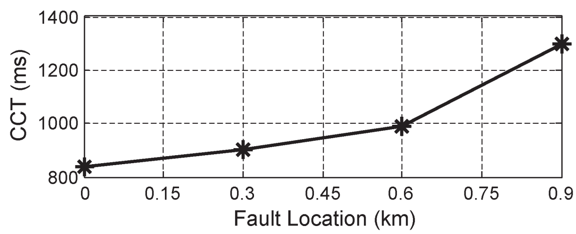

Fig. 3. CCT versus fault location for phase-to-phase faults.

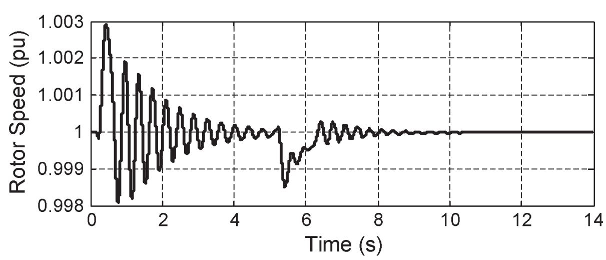

Fig. 4. Rotor mechanical speed for a single-phase-to-ground fault.

B. CCT versus Fault Location and Fault Type

In order to determine the CCT, some simulations should be performed with different fault durations. First, the simulation is started with the long time duration of approximately 2 s. If the system remains stable, the fault duration is decreased with a permissible time step. Once the transient instability occurs, the previous fault duration is introduced as the CCT. In this section, the CCT is calculated for various faults at different locations of the 3-km outgoing overhead line. The obtained CCTs versus the fault location are shown in Figs. 2 and 3 for three-phase and phase-to-phase faults, respectively. As shown in these figures, the farther the fault location, the higher the amount of CCT. In addition, the calculated CCT for the phase-to-phase faults is much more than that for the three-phase faults at the same location.

It is also found that none of the generators become unstable for the phase-to-phase faults beyond the 0.9 km of the outgoing feeder. The simulation results indicate that the single-phase-to-ground faults do not create a serious problem for the generators. No transient instability occurs for these faults as the interconnection transformer neutral is grounded using a resistor in order to limit the single-phase-to-ground fault currents to the rated current of the transformer. Fig. 4 shows the speed of the generator when a single-phase-to-ground fault is applied to the 20-kV bus bar. The fault occurs at 200 ms and lasts for 5 s. The figure shows that during and after the fault clearance, the generator can retain its normal speed.

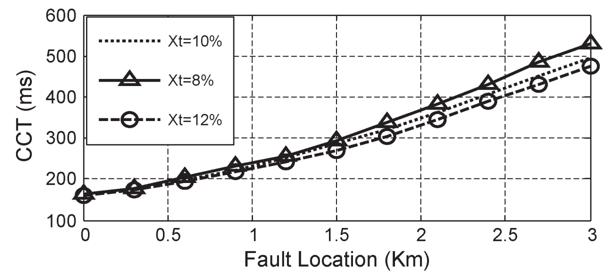

Fig. 5. CCT versus interconnection transformer impedance.

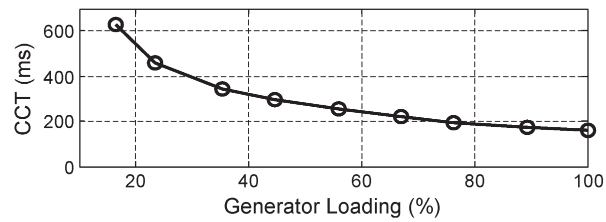

Fig. 6. CCT versus generator loading.

C. CCT versus Interconnection Transformer Impedance

Interconnection transformer parameters, particularly its short-circuit impedance, might have some effects on the transient stability of the generator. The typical value for the transformer impedance is about 10%. In this section, the deviation of this parameter from its normal value is investigated.

To do this, 12% and 8% are considered as the higher and lower values for the transformer short-circuit impedance. Fig. 5 shows the CCT versus the transformer short-circuit impedance at different fault locations. This figure shows that the short-circuit impedance of the interconnection transformer does not have a significant effect on the transient stability of the generators, particularly for the nearby faults.

D. CCT versus Generator Loading

The prefault loading of the generator affects its transient stability. For the generators operating at the higher loading level, the occurrence of the instability is more probable because according to the equal-area criterion, the accelerating area increases and this helps the rotor to accelerate more and become unstable rapidly.

Fig. 6 shows the CCT versus the generator loading. It shows that an increase in the prefault generator load decreases the CCT value. SSSGs connected to the distribution networks are commonly operated at their rated power which is the most critical operation point for the transient stability.

E. CCT versus Excitation Control Mode

Usually, DGs do not participate in the frequency regulation of the system, and therefore, they operate in constant active power mode in which the mechanical input power is considered constant [21].

SG excitation system can operate in two general control modes, i.e., constant power factor and constant terminal voltage [21]. In this paper, the effect of excitation system control modes

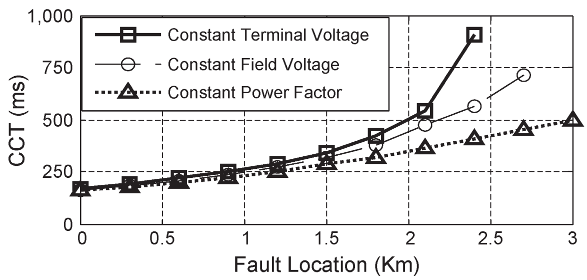

Fig. 7. CCT versus excitation system control mode.

on the transient stability is studied. Constant power factor, constant terminal voltage, and no control mode (constant field voltage) are considered as the case studies. The CCT versus the excitation control mode is shown in Fig. 7. As shown in this figure, from the transient stability point of view, the worst mode is the constant power factor and the best mode is the constant terminal voltage in which the generator boosts its output voltage during the fault. The increase of the generator terminal voltage results in more output power, and consequently, the generator becomes more stable.

However, in the constant power factor mode, the generator decreases the field current during the fault in order to decrease the output reactive power. This reduces the voltage terminal, and consequently, the transferred active power is reduced.

III. Protection of Distribution Network and Generator Stability

A. Operation of Existing Outgoing Feeder Relays

The conventional protection devices of the distribution networks' outgoing feeders include inverse and instantaneous overcurrent relays. A typical setting for the inverse overcurrent relay at the outgoing feeders is $I_{\mathrm{Pickup}} = 1$ p.u., and its time multiplier setting is equal to 0.05. Assuming a normal inverse characteristic for this relay, the operation time for a three-phase fault at the beginning of the outgoing feeder of the studied system is about 95 ms. Considering the associated additional delays and the operation time of the circuit breaker, the fault clearing time is about 170 ms at which the generators might become unstable before the fault is cleared.

Instantaneous overcurrent relay operation time is usually smaller than the CCT of the SSSG. However, if this relay is utilized, the coordination with downstream reclosers in the same feeder will be lost.

B. Proposed Method Using the Existing Relays

The proposed protection method, in which the conventional relays are utilized using a proper scheme corresponding to the feeder type and capability of DG-islanding operation, is categorized as follows.

1) Cable Outgoing Feeders Without Generator Local Load: For the cable-type outgoing feeders, the possibility of short circuit is much less than that for overhead lines [22]. Moreover, most of the faults on the cable feeders are single-phase-to-ground faults. As explained in Section II, this type of fault cannot endanger the transient stability of the generator. Therefore, a definite time overcurrent relay with the delay time of 50 ms is utilized to disconnect the SSSG for phase-to-phase or three-phase faults. Pickup current of this relay is set at 2 p.u. in order not to trip for single-phase-to-ground faults.

2) Cable Outgoing Feeder With Generator Local Load: In this case, a definite time overcurrent relay with the pickup current of 2 p.u. and a 50-ms delay time is used to trip the circuit breaker of the PCC. Moreover, to immediately clear the fault in the isolated network connected to DG, a UV relay with the setting of $U < 0.5$ p.u. and a 200-ms delay time should be used to disconnect the generator.

3) Overhead Outgoing Feeder Without Generator Local Load: The occurrence of faults on the overhead outgoing feeders is more probable. The aforementioned protection methods are not suitable here anymore as the generator will be disconnected in the case of phase-to-phase and three-phase faults on the outgoing feeders, which compose about 30% of the faults [22]. In this case, an instantaneous overcurrent relay with the pickup setting of about 8 p.u. should be used to disconnect the outgoing feeder for phase-to-phase or three-phase faults instantaneously. To prevent the transient instability of SSSG in case of the long-lasting tripping of the outgoing feeder, a backup UV relay with the setting of $U < 0.5$ p.u. and a 200-ms delay time should be used to disconnect the generator.

4) Overhead Outgoing Feeder With Generator Local Load: If the SSSG which has some local load is connected to an overhead feeder or if, in the previous case, there are some unintended trippings of the UV relay, the time delay of this relay should be set equal to 350 ms. Moreover, in this case, an out-of-step relay should be used to detect the SSSG instability and trip the generator. The type and setting of other relays are the same as the previous case.

This proposed method can solve the transient stability problem in many cases. However, it might include some shortcomings.

1) In this method, the disconnection of the generator takes place after the instability of the generator.
2) The UV relay cannot distinguish between the three-phase and phase-to-phase faults, while from the stability point of view, the fast tripping of the generator in the case of the phase-to-phase faults is not necessary.
3) Using instantaneous overcurrent relay, the coordination for the downstream reclosers in the outgoing feeders will be lost.

Moreover, according to [23], if an out-of-step relay is used, an in-depth transient stability study is required and the manufacture's preliminary settings cannot be relied upon.

In this paper, a novel practical protection scheme is proposed. This scheme can prevent the unstable operation of the generator and increases the availability of the DG units. In other words, a new relay is proposed to solve the aforementioned problems.

C. Proposed Protection Scheme

According to Section II, for the phase-to-phase and distant three-phase faults, the value of CCT is much higher than that for the nearby faults. Therefore, for these faults, the protection

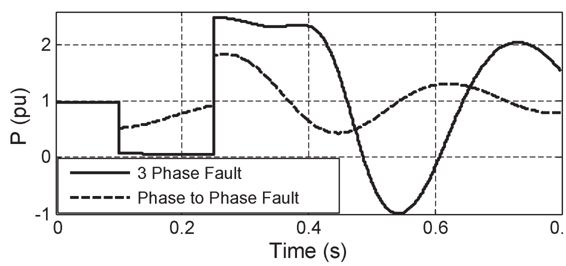

Fig. 8. Generator active power for a three-phase fault.

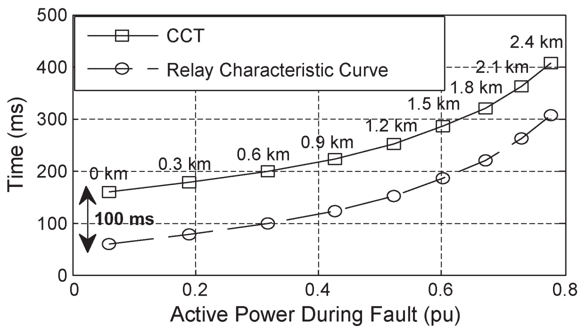

Fig. 9. CCT-versus-P and relay characteristic curves.

system has enough time to disconnect the faulty feeder from the network before the SSSG transient instability occurs, and it is not necessary to disconnect the generator immediately. So, the protection scheme should distinguish the faults according to their importance from the transient stability point of view.

The proposed method is principally based on the equal-area criterion, i.e., the stability of the generator is mainly dependent on its output active power during the fault. The higher amount of transferred power during the fault increases the decelerating area and enhances the stability margin of the generator. Therefore, the generator active power during the fault could be considered as a proper indicator to predict its instability.

Fig. 8 shows the active power of one of the studied generators while the three-phase and phase-to-phase faults on the bus bar occur at $t = 100$ ms and they are cleared at $t = 250$ ms. It shows that the generator output active power is reduced significantly during the fault. In addition, the reduction in the amount of transferred active power during the phase-to-phase fault is less than that for the three-phase fault. Moreover, the amount of active power during the fault changes rapidly, whereas it is almost constant for the three-phase fault.

Considering the delays in the calculation of the active power (P), the amount of P after 50 ms from the fault initiation is calculated for the three-phase faults at different distances. The CCT-versus-P curve for these faults is shown in Fig. 9. The distance of the fault from the bus bar is also shown in this figure. The higher amounts of transferred active power and CCT correspond to the farther faults. Thus, for the farther faults, there exists enough time to disconnect the generator before it becomes unstable. This provides more time to keep the generator connected to the network, and it complies with the FRT requirements. The obtained curve is utilized to determine the appropriate operation time for the proposed relay based on the fault location before the occurrence of the SSSG transient instability.

An appropriate inverse-type characteristic curve should be selected for the proposed P-based protective relay. Considering the operation time of the circuit breaker and also a safety margin in order to guarantee the secure operation of the proposed relay, a 100-ms time difference is considered as the margin between the proposed relay characteristic curve and the CCT-versus-P curve, as shown in Fig. 9.

D. Algorithm

For the proposed P-based relay, the inputs are the three phases' voltages and currents measured at the SSSG terminal with the sampling frequency of 1 kHz. The algorithm is based on the amount of the active power during the fault. Therefore, the phasors of all of the input voltages and currents should be calculated. Using these phasors, the total active power is calculated. The calculated active power based on this method has an insignificant fluctuation which does not affect on the relay operation time considerably. Therefore, it can be a simple and efficient method to calculate the active power.

According to Fig. 9, the relay operation range is limited to $P < 0.8$ p.u. in order to guarantee the secure operation of the relay during system transients. The system transients, e.g., load rejection, can cause power swings in the system. These swings can endanger the secure operation of the relay. Considering the limited range, the secure operation of the proposed relay can be obtained.

The flowchart of the proposed method algorithm is shown in Fig. 10. To augment the security of the proposed scheme, the phasors of the three-phase currents are used to block the relay in the case of load rejection. This logic is based on the fact that if the current phasors for two out of the three phases are greater than 1.5 p.u., it indicates that a fault has occurred. Otherwise, the relay is blocked. This is an appropriate logic as the load change does not increase the generator currents up to 1.5 p.u.

The detection of a fault activates the P-based relay. If the calculated power is less than 0.8 p.u., according to the relay characteristic curve shown in Fig. 9, the relay operation time is calculated and the value of relay counter is increased. This process will continue until the counter value becomes greater than one. In this case, the trip signal will be sent to the circuit breaker.

The resetting algorithm is designed to prevent the relay operation during generator oscillations or in the case of downstream faults. Several logics have been employed for the reset characteristics of industrial relays. In this paper, after performing comprehensive simulation studies, a simple and appropriate method is utilized to reset the relay when the tripping conditions are not met. In this method, the last calculated counter is multiplied by 0.8 until the counter reaches to a value less than 0.08.

This resetting strategy enables the algorithm not to trip for the phase-to-phase faults. During these faults, as it is shown in Fig. 8, the amount of generator active power increases during the fault and becomes greater than 0.8 p.u. So, the relay will be reset. It should be considered that the presetting value (0.8) is

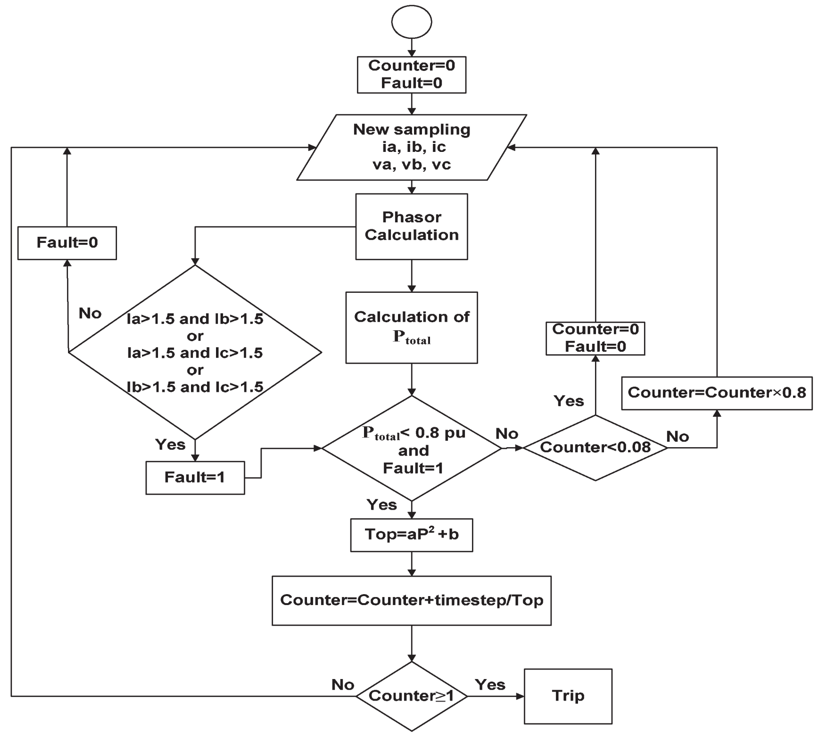

Fig. 10. Flowchart of the proposed algorithm.

TABLE I
CLEARING TIME AND CCT FOR DIFFERENT FAULTS

Fault type –Fault location	Clearing time (ms)	CCT(ms)
Single phase-Bus bar	No operation	Stable
Phase to phase-Bus bar	No operation	837
Three phase-Bus bar	139	160
Three phase-0.3 km	153	178
Three phase-0.6 km	178	198
Three phase-0.9 km	210	222
Three phase-1.2 km	244	252
Three phase-1.5 km	277	286
Three phase-1.8 km	308	320
Three phase-2.1 km	332	363
Three phase-2.4 km	350	407
Three phase-2.7 km	No operation	451
Three phase-3 km	No operation	495

in p.u. based on the value of the generator steady-state prefault load, not the generator rated power.

E. Simulation Results

The system shown in Fig. 1 is used to test the performance of the proposed method. Table I illustrates the clearing time, generator disconnection time, and CCT for the different types of faults at different locations of the 3-km overhead line. In this table, the fault location indicates the distance of the fault from the bus bar, and the clearing time includes the operation time of the relay plus the operation time of the circuit breaker which is considered to be 80 ms. Obtained results indicate that for all of the studied cases, the clearing time is less than the CCT value.

In addition, for single-phase-to-ground, phase-to-phase, and three-phase faults at the end of the line, which do not endanger the transient stability of the generators, there is enough time to clear the fault, and it is not necessary to disconnect the generators immediately. For these faults, other protective relays with sufficient delay times protect the generator.

Some classical relays, particularly the UV relay, have been utilized as a classical method to protect the SG against transient instability [12]. However, the generator may be disconnected by this relay for unnecessary conditions such as the two-phase and distant three-phase faults. Moreover, the recommended clearing fault time by the UV relay is 160 ms [12]. This short clearing time results in the miscoordination of the UV relay with the downstream system. Consequently, not only the protective relay of the faulty outgoing feeder operates for two-phase and three-phase short circuits but also the generator is disconnected by the UV relay which decreases the DG availability [18].

This method presents a very robust and reliable scheme to protect the generators against instability, and also, it complies with the generators FRT requirement.

F. Robustness of the Proposed Algorithm

To examine the robustness of the proposed relay algorithm in different system operational conditions, several possible conditions have been considered. These conditions include a change in the short-circuit capacity of the external grid, change in the number of the generators, and change in the number of the interconnection transformers.

The system shown in Fig. 1 is used for this paper. To examine the safe operation of the relay in all of these conditions, it is enough to examine the changes in the characteristic curve of the relay. Fig. 11 shows the sensitivity of the relay characteristic to these system changes.

In this figure, “2 transformers” is corresponding to a case when one of the interconnection transformers is disconnected.

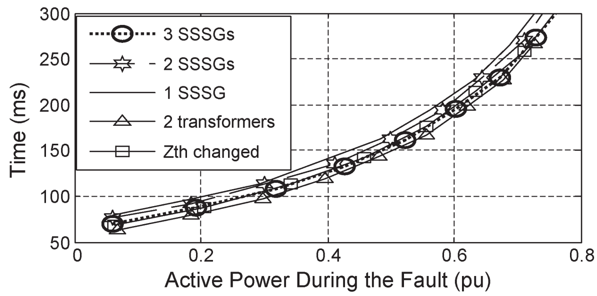

Fig. 11. Relay characteristic curve for different changes in the system.

TABLE II
AMOUNT OF PARAMETERS

Condition	a	b
3 SSSGs	388.2	55.2
2 SSSGs	397	61.5
1 SSSG	401	66.5
2 transformers	394.5	50
Zth changed	390	55

In the second condition ("Zth changed"), three interconnection transformers are available in the system, whereas the short-circuit capacity of the external grid is increased. In other words, the equivalent impedance of the external grid decreases. Using an appropriate curve fitting method, all these curves can be expressed by

$$T_{\rm op} = aP^2 + b. \quad (1)$$

Table II indicates the estimated "a" and "b" parameters. It shows that these parameters do not change significantly for various system conditions. This is a very desirable feature which enables the application of this relay in different systems and conditions.

As a complementary study, a system with a 15-MVA generator connected directly to the 20-kV bus bar and a 10-MVA generator connected to the bus bar via a 4-km cable feeder are investigated. Our studies show that the proposed algorithm is insignificantly influenced by the presence of other generators. Therefore, the applicability of the proposed algorithm is guaranteed without the need to change the relay characteristic based on the system configuration.

G. System Transients Effects on Operation of the Proposed Relay

A secure protection scheme should operate correctly during the transients of the power system. The proposed relay is mainly based on the generator active power. Thus, power swings should not affect the secure operation of the proposed algorithm. In this section, the operation of the proposed algorithm is tested during system transients. To do this, a large load rejection and a transient fault are subjected to the system. The generator total active power during the load rejection condition is shown in Fig. 12. As shown in this figure, the amount of power is higher than 0.8 p.u., and therefore, the relay is not activated.

Fig. 13 shows the total active power and counter value for the transient fault case. For this fault, the counter increases for a short duration, but it resets quickly. These results show that the proposed relay has a secure operation during system transients.

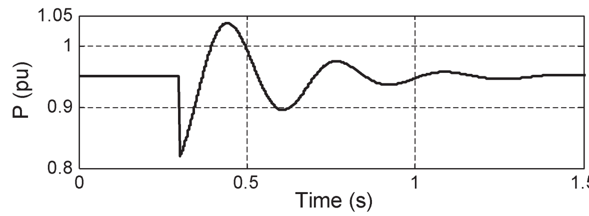

Fig. 12. Generator active power during load rejection condition.

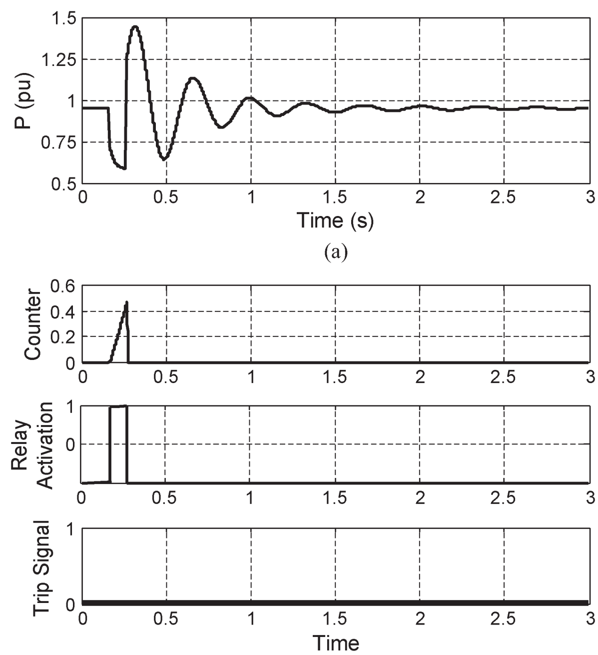

Fig. 13. Transient fault conditions: (a) Active power and (b) trip signal.

H. Feasibility of the Algorithm for a Small DG

As a complementary study, to investigate the feasibility of employing the proposed algorithm for a smaller DG, i.e., an 880 kVA, a 0.4-kV SG connected to the 20-kV bus bar is simulated. The fault clearing time as compared with the CCT is shown in Table III. Since the generator is disconnected before the CCT, the proposed relay operates correctly before the occurrence of transient instability for the case of a smaller generator.

I. Operation of the Proposed Relay for Different Prefault Loads

The proposed relay should operate correctly when its output power changes during normal operation. To investigate this issue, the proper relay characteristics for the three prefault load conditions, calculated based on the described method in Section III-C, are shown in Fig. 14. The decrease of the generator prefault active power results in the increase of the CCT. Therefore, if the relay characteristic is set based on the rated

TABLE III
OPERATION OF THE PROPOSED RELAY FOR A SMALLER GENERATOR

Fault type–Fault location	Clearing time (ms)	CCT(ms)
Single phase-Bus bar	No operation	Stable
Phase to phase-Bus bar	No operation	741
Three phase-Bus bar	128	142
Three phase-0.3 km	140	157
Three phase-0.6 km	159	172
Three phase-0.9 km	180	192
Three phase-1.2 km	195	212
Three phase-1.5 km	209	235
Three phase-1.8 km	221	258
Three phase-2.1 km	230	282
Three phase-2.4 km	236	305
Three phase-2.7 km	241	325
Three phase-3 km	No operation	344

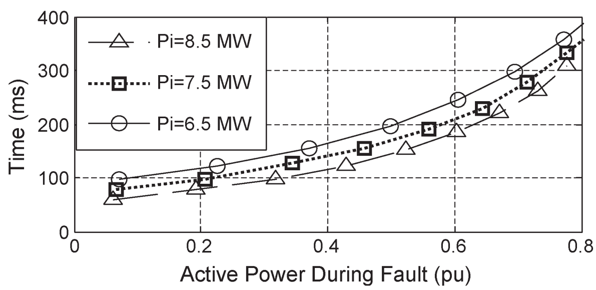

Fig. 14. Relay characteristic curves for different amounts of prefault loads.

TABLE IV
EQUATION PARAMETERS FOR DIFFERENT PREFAULT LOADS

Pre-fault load (MW)	a	b
6.5	388.2	55.2
7.5	390	82.19
8.5	390	110.1

active power (the lower one in Fig. 14), other load conditions will be covered and the relay would have correct operation.

In addition, in order to increase the flexibility of the proposed relay, the characteristic curve can be determined adaptively based on the calculated generator prefault active power during the steady-state condition. As it is shown in Table IV, although the relay characteristic curves shift upward for smaller prefault load values [the increase of parameter "b" in (1)], the parameter "a" remains approximately constant. Therefore, the parameter "b" can be adaptively adjusted after the change of generator output power based on a look-up table. This lookup table should be predetermined based on offline simulation studies.

IV. CONCLUSION

This paper has presented an extensive study to investigate the dynamic behavior of the small-scale generators connected to the distribution networks. The objective was to propose a new algorithm to protect these generators against instability and also to comply with DG FRT requirements. To do this, the sensitivity analysis of the transient stability to the system parameters was performed, and it was concluded that the most severe faults are the three-phase faults. Generally, phase-to-phase faults are not a serious danger for the generators, and single-phase-to-ground faults do not threaten the transient stability of the generators. In addition, the power factor control mode of the excitation system is the most critical operation mode of the generator.

Then, a protection method using the existing conventional relays was presented. It was shown that this method can solve the SSSG's transient stability problem in many cases. However, it might have some shortcomings. Thus, using the information obtained from the sensitivity analysis, a novel protective relay was proposed. The proposed algorithm is based on the CCT–P curve of the generator and presents an effective way to prevent instability of the generator. In addition, this algorithm complies with the FRT requirements of the generator. The simulation results confirmed the effectiveness of the proposed algorithm for different fault conditions and also its robustness against system changes. In addition, the proposed relay is applicable for smaller SGs.

APPENDIX

The electrical parameters of SSSGs and other apparatus utilized in the studied system are tabulated as follows:

TABLE A1
GENERATOR PARAMETERS

Parameter	Value
Rated power (S)	10913 kVA
Voltage (V)	11 kV
Synchronous reactance (Xd)	1.919 pu
Transient reactance (X'd)	0.283 pu
Sub-transient reactance (X''d)	0.183 pu
Stator winding resistance (Ra)	0.00507 pu
Inertia constant (H)	1 s

TABLE A2
INTERCONNECTION TRANSFORMER PARAMETERS

Parameter		Value
Rated power (S)		12 MVA
Rated voltage	HV-side	20 kV
	LV-side	11 kV
Short circuit voltage (Uk)		10%
Ratio X/R		25

TABLE A3
SYSTEM TRANSFORMER PARAMETERS

Parameter		Value
Rated power (S)		30 MVA
Rated voltage	HV-Side	63 kV
	LV-Side	20 kV
Short circuit voltage (Uk)		12.5%
Ratio X/R		35

TABLE A4
EXTERNAL GRID PARAMETERS

Parameter	Value
External grid voltage	63 kV
External grid short circuit current	10 kA
X/R ratio	8

REFERENCES

[1] T. Ackermann, G. Andersson, and L. Söder, "Distributed generation: A definition," *Elect. Power Syst. Res.*, vol. 57, no. 3, pp. 195–204, Apr. 2001.
[2] P. Siano, L. F. Ochao, G. P. Harrison, and A. Piccolo, "Assessing the strategic benefits of distributed generation ownership for DNOs," *IET Gener., Transm. Distrib.*, vol. 3, no. 3, pp. 225–236, Mar. 2009.

[3] K. H. Ahmed, A. M. Massoud, S. J. Finney, and B. W. Williams, "A modified stationary reference frame-based predictive current control with zero steady-state error for LCL coupled inverter-based distributed generation systems," *IEEE Trans. Ind. Electron.*, vol. 58, no. 4, pp. 1359–1370, Apr. 2011.
[4] Q. Zeng and L. Chang, "An advanced SVPWM-based predictive current controller for three-phase inverters in distributed generation systems," *IEEE Trans. Ind. Electron.*, vol. 55, no. 3, pp. 1235–1246, Mar. 2008.
[5] J. He, Y. WeiLi, and M. S. Munir, "A flexible harmonic control approach through voltage-controlled DG-grid interfacing converters," *IEEE Trans. Ind. Electron.*, vol. 59, no. 1, pp. 444–455, Jan. 2012.
[6] P. P. Barker and R. W. de Mello, "Determining the impact of distributed generation on power systems: Part 1—Radial distribution systems," in *Proc. IEEE PES Summer Meeting*, 2000, vol. 3, pp. 1645–1656.
[7] P. Rodriguez, A. V. Timbus, R. Teodorescu, M. Liserre, and F. Blaabjerg, "Flexible active power control of distributed power generation systems during grid faults," *IEEE Trans. Ind. Electron.*, vol. 54, no. 5, pp. 2583–2592, Oct. 2007.
[8] C. J. Mozina, "Interconnect protection of dispersed generators," in *Proc. IEEE Transmission Distrib. Conf. Expo.*, 2001, vol. 2, pp. 707–723.
[9] P. Kundur, *Power System Stability and Control*. New York: McGraw-Hill, 1994.
[10] "Proposed terms and definition for power system stability," *IEEE Trans. Power App. Syst.*, vol. PAS-101, no. 7, pp. 1894–1898, Jul. 1982.
[11] W. Freitas, J. C. M. Vieira, A. Morelato, L. C. P. da Silva, V. F. da Costa, and F. A. B. Lemos, "Comparative analysis between synchronous and induction machines for distributed generation applications," *IEEE Trans. Power Syst.*, vol. 21, no. 1, pp. 301–311, Feb. 2006.
[12] *IEEE Standard for Interconnecting Distributed Resources With Electric Power Systems*, IEEE Std. 1547-2003, 2003.
[13] *Impianti di Produzione di Energia Elettrica e Gruppi di Continuità Collegati a Reti di I e II Categoria*, Italian Standard CEI 11-20, Aug. 2000.
[14] E. J. Coster, J. M. A. Myrzik, and W. L. Kling, "Effect of grid disturbances on fault-ride-through behaviour of MV-connected DG-units, in especially CHP-plants," in *Proc. Integr. Wide-Scale Renew. Resources Into Power Del. Syst., CIGRE/IEEE PES Joint Symp.*, Calgary, AB, Canada, 2009, pp. 1–11.
[15] M. Alberdi, M. Amundarain, A. J. Garrido, I. Garrido, and F. J. Maseda, "Fault-ride-through capability of oscillating-water-column-based wave-power-generation plants equipped with doubly fed induction generator and airflow control," *IEEE Trans. Ind. Electron.*, vol. 58, no. 5, pp. 1501–1517, May 2011.
[16] I. Xyngi, A. Ishchenko, M. Popov, and L. van der Sluis, "Protection, transient stability and fault ride-through issues in distribution networks with dispersed generation," in *Proc. 43rd Int. Univ. Power Eng. Conf.*, Padova, Italy, 2008, pp. 1–5.
[17] E. J. Coster, J. M. A. Myrzik, and W. L. Kling, "Influence of protection on transient stability of medium voltage grids including distributed generation," in *Proc. Univ. Power Eng. Conf.*, England, 2007.
[18] I. Xyngi, A. Ishchenko, M. Popov, and L. van der Sluis, "Transient stability analysis of a distribution network with distributed generators," *IEEE Trans. Power Syst.*, vol. 24, no. 2, pp. 1102–1104, May 2009.
[19] S. Paudyal, G. Ramakrishna, and M. S. Sachdev, "Application of equal area criterion conditions in the time domain for out-of-step protection," *IEEE Trans. Power Del.*, vol. 25, no. 2, pp. 600–609, Apr. 2010.
[20] R. F. Arritt and R. C. Dugan, "Distributed generation interconnection transformer and grounding selection," in *Proc. IEEE Power Energy Soc. Gen. Meeting*, 2008, pp. 1–7.
[21] W. Freitas, J. C. M. Vieira, A. Morelato, and W. Xu, "Influence of excitation system control modes on the allowable penetration level of distributed synchronous generators," *IEEE Trans. Energy Convers.*, vol. 20, no. 2, pp. 474–480, Jun. 2005.
[22] Nordel Disturbance Statistics, Grid Disturbance and Fault Statistics, 2007. [Online]. Available: www.nordel.org
[23] K. Malmedal, P. K. Sen, and J. P. Nelson, "Application of out-of-step relaying for small generators in distributed generation," *IEEE Trans. Ind. Appl.*, vol. 41, no. 6, pp. 1506–1514, Nov./Dec. 2005.

Reza Razzaghi received the B.Sc. and M.Sc. degrees in electrical engineering from the University of Tehran, Tehran, Iran, in 2009 and 2011 respectively.

His research interests include power system protection, distribution systems, and the real-time simulation of power system.

Mahdi Davarpanah received the B.Sc. degree in electrical engineering from the Power and Water University of Technology, Tehran, Iran, in 2022 and the M.Sc. degree from the University of Tehran, Tehran, in 2005, where he is currently working toward the Ph.D. degree.

His research interests include power system protection, distribution systems, and the study and simulation of electromagnetic transients in power systems and apparatus.

Majid Sanaye-Pasand (M'98–SM'05) received the B.Sc. degree in electrical engineering from the University of Tehran, Tehran, Iran, and the M.Sc. and Ph.D. degrees from the University of Calgary, Calgary, AB, Canada.

He is currently a Professor with the Control and Intelligent Processing Center of Excellence, School of Electrical and Computer Engineering, University of Tehran. His research interests include power system protection, control, and transients.