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Design of an adaptive overcurrent protection scheme for microgrids

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Abstract

Microgrid is a new phenomenon regarded to Distributed Generation (DG) penetration in the existing distribution systems. In this paper adaptive over current (OC) protection technique for a distribution system with DG penetration is proposed. This scheme takes into account general protection requirements, impacts of DG on protection system and protection coordination. A part of IEEE 13 nodes radial distribution test feeder is taken as a study case to test the effectiveness of the proposed scheme using ETAP software.

Keywords: Distributed Generator, Microgrids, Adaptive overcurrent protection, Protection Coordination.

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1. Introduction

Based on environmental concerns related to emitted gases from conventional generation and the world trend to green energy generation, DG technology has been developed. DG wide spread in distribution systems leads to an appeared phenomenon in power system called Microgrids (MG). As a matter of fact MG can be seen as a group of DG units that can be operated either grid-connected to limit transmission losses and for peak shaving or islanded to avoid total outage when main utility get interrupted and hence increasing system reliability (Waleed et al., 2013). On the other hand, MG is considered as a collection of loads and generators with some local storage, which may appear as a net load or a net generator to the broader or host grid (Taha et al., 2012).

Even though DG connection to distribution system brings numerous benefits for MG, it poses significant challenges due to unforeseen short circuit (SC) increase in radial distribution system (Stefania, 2009), different fault levels during different topologies due to source change (Pukar et al., 2011; Andrés et al., 2012), bidirectional Power flow (Sachit et al., 2014), lack or in some cases completely loss of coordination in the existed protection scheme leads to undesired islanding and untimely tripping of DGs protection relays (Stefania, 2009; Sachit et al., 2014), and a high DG penetration has resulted in the possibility of operating distribution system in islanded mode which has an issue in conventional OC protection system and needs a new requirement in protection scheme (Pukar et al., 2011).

From the above mentioned challenges , it is clear that SC level is affected due to DGs insertion in distribution system that's because fault current depends on source MVAs.c., and as MVAs.c. of main utility is higher than MVAs.c. of DG, so fault current in grid connected will be higher than fault current in islanded mode of operation (Pukar et al,2011). This fault level variation impacts on protection system as following (Pukar et al, 2011):

1- If protective devices are adjusted to high fault values (as in conventional system), they will take longer time to trip or may not trip at all when distributed system is converted to islanded mode.
2- If distributed system now is transferred to islanded mode but protective devices are still adjusted to grid connected values (i.e. higher fault levels). In this case if a fault is happened inside island itself and as any fault is followed by voltage drop, so by not clearing the fault quickly not only loads but also some DGs will forced to be switched off. For example equipment like M.V motors have a voltage variation limit to operate (+/- 10% of rated voltage) and also DGs.

3- If protective devices are adjusted to islanded mode faults (i.e. low fault levels), they will make a false tripping when system reconnected to the main utility.

Another important issue relate to DG penetration in distribution system is that DG changes the original (S.C and steady state) current values and directions on which relay settings in original radial system were calculated. Therefore IEEE std 1547 suggests that to maintain relays coordination due to high penetration of DGs, all DGs should be disconnected simultaneously after fault happen (IEEE Std 1547, 2003), this would regain the system to its radial nature and hence maintain original relay coordination. However this solution isn't practical as DG becomes popular because it can feed loads without adding to T&D burden, so throwing off all DGs every time a temporary fault happens would make the system unreliable, leads to sever stability problems and DG synchronization problem during reconnecting again to distribution system after fault clearing (N. Schaefer et al, 2010; Sukumar et al, 2004; W. El-khattam et al, 2009; Ehsan et al, 2010). So it's expected in near future that DG will remain connected during grid faults for feeding MG (N. Schaefer et al, 2010).

An attempt to solve different S.C. levels between grid-connected and islanded modes of operation is to insert a storage unit with MG for upgrading its S.C. level to values near the fault contributed by main grid to make MG fault possible to be detected by traditional relays. However storage units require large investment and don't guarantee fault clearing on time unless they match main grid S.C. power (Pukar et al., 2011).

Based on the above mentioned DG impact on protection system, it's clear that conventional protection system will show a bad response to MG protection, as MG has an operating philosophy which is under normal condition MG should operate in Grid-connected mode and in case of disturbance in main grid MG should continue to work in islanded mode. Therefore a new protection technique that able to respond to both modes of operations is required (Sachit et al., 2014; Sohrab et al, 2014; Sohrab, Dalila et al., 2014).

As a result of that, various schemes for MG protection have been proposed which are adaptive protection, differential protection, OC and symmetrical components, distance protection, voltage based protection and deployment of external devices (Sachit et al, 2014; Sohrab et al., 2014; Sohrab, Dalila et al., 2014). Based on the comparison among these various protection schemes, as proposed in (Sachit et al, 2014), it is clear that adaptive technique is cost reasonable and can be achieved with or without communication links, therefore in this research point we will deal with adaptive OC as a protection technique for MG, which can be defined as " An online activity which is automatically able to change protection system parameters – either by externally generated signals or control action- to adapt them with new system configurations maintaining the basic criteria of sensitivity, selectivity, speed and reliability which guarantee a coordinated protection system " (Pukar et al, 2011; Andrés et al., 2012; A.Y. Abdelaziz et al., 2002).

Basically different adaptive techniques are existed and some of them are mentioned here. An adaptive protection scheme is proposed in (Alexandre et al., 2010) where a communication system connects MGCC to each directional OC relay. Off-line analysis is performed by constructing an event table for C.B statuses and an action table for relay settings in all MG configurations. During online operation, the MGCC is monitoring MG operating state and using the event and action tables to select relays settings according to the current configuration. During real-time operation, the measured current values are compared with the relay settings to detect a fault if it is occurred. Fault current direction is also checked against an interlock direction. This scheme has the advantages of adapting to several MG configurations and Providing Protection for all fault types, but this scheme is not efficient for larger MG configurations due to excessive memory used to store large amounts of off-line analysis data. Authors in (Pukar et al., 2011) propose adaptive protection using local information only, to overcome the challenges of the OC protection in distribution systems with DG. Relays trip characteristics are updated by detecting MG operating states (grid connected or island or lose of some generators) and the faulted section. The faulted section is detected using time OC characteristics of directional OC relays. This adaptive technique uses the state detection algorithms to know the network current condition and use also detection of the faulted section algorithm to update the relays trip characteristics to clear the fault as soon as possible. Here adaptive protection is realized with the use of microprocessor-based DOCR and local information only which has the advantage that any problem with a relay will be confined in the relay itself. Authors don't uses communication system to update relay settings as they see communication system is complex and require high cost and isn't economical for small distribution systems. In (Hannu et al., 2010), an adaptive protection scheme for a LVMG using communication network between MG Management System (MGMS) and MG components (DGs, Relays, ..) is proposed. MGMS detects MG configuration change and sends the appropriate settings and pick-up limits to relays. This scheme protects against double phase faults. High speed communication links provide fast, selective, and reliable protection. However, it doesn't take into consideration the possibility of communication network failure and it also doesn't support plug-and-play DGs.

In the light of the above mentioned techniques, authors in (W. El-khattam et al., 2009) had summed up MG protection techniques to two approaches to solve DOCR coordination problem as shown in Table 1.

Table 1. Two approaches to solve the directional OC relay coordination problem associated with DG installation

<table>
<tr><th colspan="2">Adaptive</th><th>Non-Adaptive</th></tr>
<tr><td colspan="2">- Adaptive approach depends on changing or adapting relay setting based on system different topologies between (PG only or PG +All DGs or islanded or islanded+ (n-1) DGs).
-It requires that relays must have multi SGF (switch group factor).
-Relays settings can be changed by either Communication or Communicationless.</td><td rowspan="3">-Non-adaptive approach depends on inserting an external device like FCL with either main utility (to limit utility contribution to fault –when it is connected- and hence adjust relay setting for fault values of islanded mode) (Waleed et al, 2013) or with DG(to limit DG contribution to fault to keep relay setting without changes as traditional system without DGs).FCL isn't inserted with all DGs in system, but optimal placement is made to select the best DG to insert FCL (W. El-khattam et al, 2009).
- Finally, FCL insertion aims to not changing relay setting with different configurations (i.e. use one setting group)</td></tr>
<tr><td>Communication</td><td>Communicationless</td></tr>
<tr><td>- A communication network is connected between the MGCPU and the different MG component.
- MGCPU detecting the change in MG configuration and sends the appropriate settings and pick-up limits to the protective devices for each component (Hannu et al, 2010).</td><td>The idea here is depending on programming each relay independently for all possible configurations based on system configurations variation, using local information only. Regarding local information only has an advantage which is any problem with a relay will be related to relay itself (Pukar et al, 2011).</td></tr>
</table>

An integration of the proposed two approaches (Adaptive & Non-adaptive) is evolved in (W. El-khattam et al., 2009) trying to overcome problems that might appear due to the limitation of the above mentioned two approaches.

This work has a purpose to identify the impact of DG insertion on protection system of distribution grids, and hence the protection requirements in the technique used to deal with these issues. Based on these requirements and different protection schemes for MG, this work pretends to propose an adaptive OC protection technique for MG which responds, with all requirements that maintain protection coordination, to a time-variable system like distribution system with DGs.

This paper is organized as follows: section 2 presents system case study and selection of system parameters and sources. Section 3 presents protection impacts and requirements in system with DGs. Section 4 shows adaptive OC protection for distribution system with DG. Section 5 shows adaptive protection scheme results. In section 6 conclusion is presented. Finally references are listed.

2. System case study

System case study is a part of IEEE 13 Bus test feeder and the One Line Diagram (OLD) is shown in Figure 1. System cable and T.Ls data are existed in (W.H. Kersting, 2001).

2.1 System Sources: Main utility ratings are 115 kV, 3984 MVAs.c. Also there are 3 DGs which are (Synchronous Generator (Syn G1) at node 611: 1000 kW, 4.16 kV), (Synchronous Generator (Syn G2) at node 692: 1200 kW, 4.16 kV) and (two Wind Turbine Generator (WTG) at WTG bus each one is 300 kW, 0.69kV).

With DG insertion in the system, multi configurations are evolved. In this work only 6 configurations are presented:

Configuration1: Power Grid (PG) only. Configuration2: PG +All DGs.

Configuration3: Islanded (IS) + All DG's. Configuration4: Is+ (All DG's - no WTG).

Configuration5: Is+ (All DG's – no DG1). Configuration6: IS+ (All DG's - no DG2).

2.2 System Parameters Selection: All system Parameters (C.Bs, CTs, Switches, Buses, T.Ls and cables) are designed to withstand continuously and without damage maximum (faults and normal currents) that they may carry in different topologies. As motioned in the introduction S.C. level is depends on MVAs.c of source, so system parameters are designed based on Config. 2 (PG+All DGs) as it contains all sources in service so it has maximum current and fault values as shown in Figure 2.

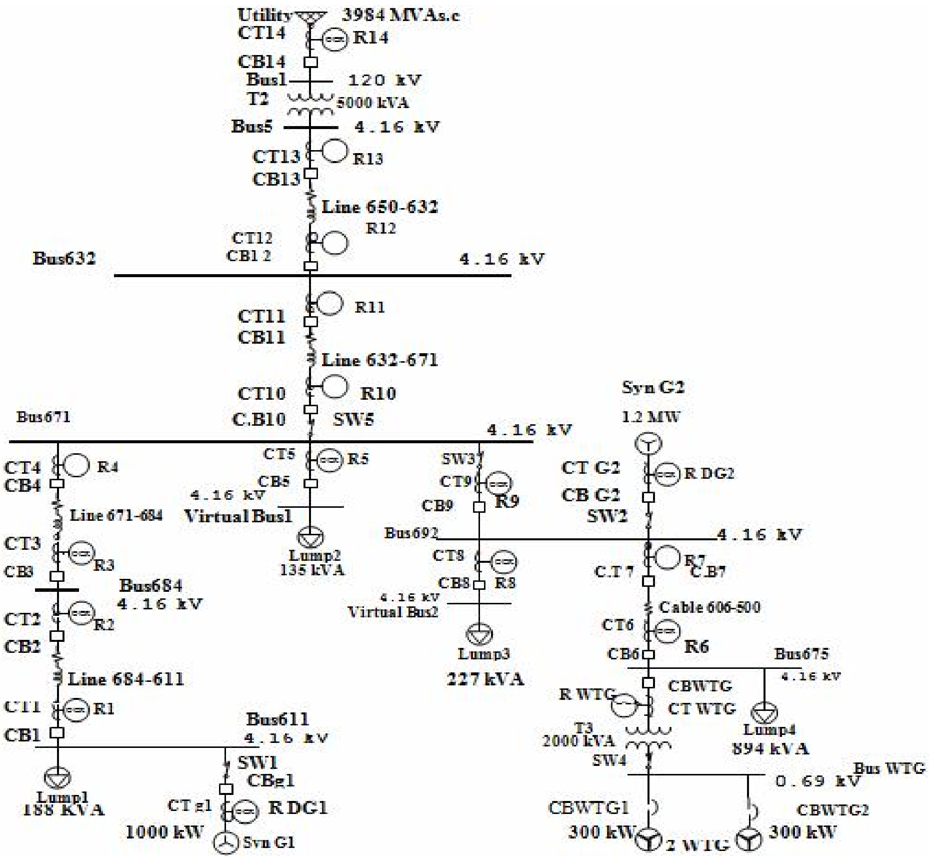


Figure 1. System case study OLD including DGs.

Table 2 (a&b) shows maximum fault and maximum current that can be seen by different system parameters.

Table 2

(a) Relays, CTS and CBs max FLA and S.C.

Relay	C.T	C.B	Max. fault seen by C.B (kA)	Max. FLA seen by C.B
R G1	CT g1	C.B g1	3.19	171.3
R1	CT1	C.B1	3.57	150.2
R2	CT2	C.B2	3.57	150.2
R3	CT3	C.B3	4.17	150.2
R4	CT4	C.B4	4.17	150.2
R5	CT5	C.B5	7.8	19
R WTG	CT wtg	C.B wtg	4.43	94.808
R6	CT6	C.B6	5.85	125.6
R7	CT7	C.B7	5.85	125.6
R8	CT8	C.B8	7.73	32
R G2	CT g2	C.B g2	3.5	174.6
R9	CT9	C.B9	5.33	157.5
R10	CT10	C.B10	4.18	693.9
R11	CT11	C.B11	4.18	693.9
R12	CT12	C.B12	5.78	693.9
R13	CT13	C.B13	5.78	693.9
R14	CT14	C.B14	20.87	7.3
LV C.B wtg1,2			1.84	285.4

(b) Buses and switches max FLA and S.C.

BUS	Max. fault pass in bus (kA)	Max. FLA pass in bus
611	4.73	176.3
684	5.82	150.2
Virtual Bus1	7.89	19
Virtual Bus2	7.89	32
WTG Bus	30.33	571.6
675	7.13	126
692	7.89	185
671	7.89	202.3
632	8.85	202.3
Bus 5	11.53	202.3
Bus 1	20.89	7.3
Switches	Max. fault pass in switch (kA)	Max. FLA pass in bus
S1	3.19	171.3
S2	3.5	174.6
S3	5.33	157.5
S4	27.92	571.6
S5	4.18	693.9

2.2.1 Switches selection: The switch FLA rating is designed such that the first available standard rate higher than 125% of max FLA seen by switch is selected, and the momentary capacity is selected to be the first available standard rate higher than maximum fault seen by switch as clarified in Table 3 which shows maximum (FLA and faults) seen by each switch. These values are considered during selecting switches ratings.

Table 3. Switch Selection Table

Switch	Max (A) seen	Switch Rating (A)	Max (kA) seen	Switch momentary (kA)	Rated (kV)	BIL (kV)
SW1	171.3	300	3.19	6	4.8	24
SW2	174.6	300	3.5	6	4.8	24
SW3	157.5	200	5.33	6	4.8	30
SW4	571.6	800	27.92	30	1	10
SW5	693.9	800	4.18	6	4.8	24

2.2.2 CTs Selection: CT saturation should be avoided because when CTs become saturated, the secondary relay current will be less than it should be and the relay operates more slowly. In some cases of severe saturation, the secondary output current could be near zero on one or more phases. To avoid the above mentioned problem the secondary CT current is best to be within (3-4 A) for 5A CT secondary (IEEE Std 242, 2001). Based on this condition system CTs are selected and samples of these CTs are given in Table 4.

Table 4. Samples of system Current Transformers CTs ratio selection

CT	Max. FLA (A)	CT secondary ampere for FLA check (A)	Max. Fault kA	CT secondary ampere for Fault check (A)
CT1- 200/5	150.2	3.75	3.57	89.25
CT2- 200/5	150.2	3.75	3.57	89.25
CT8- 50/5	32	3.2	7.73	773
CT10- 200/5	693.9	2.89	4.18	17.41
CT11- 1200/5	693.9	2.89	4.18	17.41
CT12- 1200/5	693.9	2.89	5.78	24.08
CT13- 1200/5	693.9	2.89	5.78	24.08
CT G1- 300/5	171.3	2.85	3.19	53.16
CT G2- 300/5	174.6	3.63	3.5	58.33

Table 4 shows that CTs ratio are accepted for CT secondary ampere check as CT sees current less than 4A when the maximum current passed in CT primary. Authors in (Michael et al, 2011) add an additional criterion for CT selection which says not only the maximum load current, but also the maximum secondary current under fault condition is an effective criterion for CT ratio selection. As CT secondary should not carry current more than 100A when max fault path in the Primary, however this last criterion practically is overridden, that's because if we followed this last criterion, CTs ratio had to be raised which make CT to be less sensitivity to FLA in normal operating conditions when normal current passes. This last criterion is practically cured by selecting S.C. capacity of CT to withstand without damage S.C. value in CT location inside the system. As seen in Table 4, C.T8 secondary current when FLA pass is 3.2A which is an accepted value, however the secondary current due to fault in primary is 773A. This fault requires a C.T. ratio of (400/5) to get secondary current less than 100A under fault in primary circuit, however under normal current CT secondary current will be 0.4A which may not be sensed by CT.

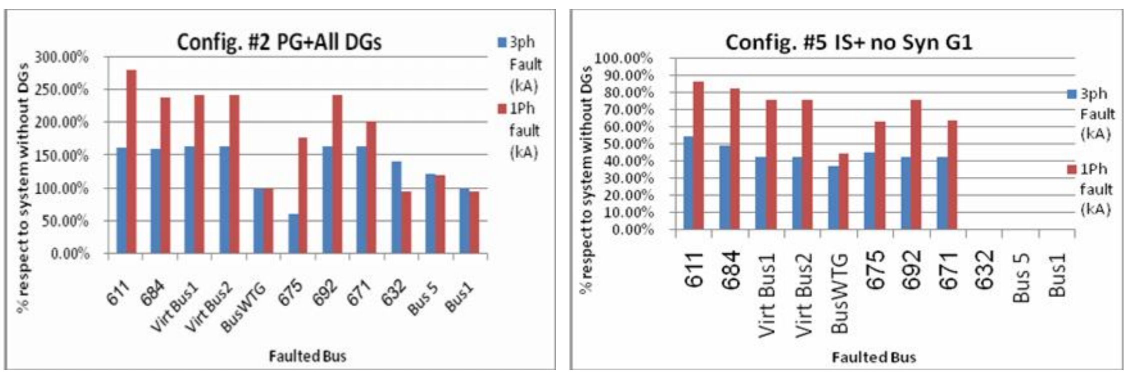
2.2.3 CBs Selection: M.V.C.B frame size is designed such that the first available standard rate which is higher than 125% of max FLA seen by CB is selected, and the interrupting capacity is selected to be the first available standard rate higher than max fault seen by CB. Table 5 shows sample of M.V.C.B ratings and breaking capacity. All system M.V.C.Bs rated voltage are 4.76 kV as system voltage is 4.16kv except C.B14 which has rated voltage of 121kV as it is used at the primary side of T2 (115/4.16) kV. For LVPCB of WTG Bus (CB WTG1&2): select C.B rated voltage to be 0.69 kV. As max. FLA= 285.4, so the rated C.B current is 400A, and the breaking capacity Ic.u = 6kA as the max fault is (1.84kA).

Table 5. Samples of system M.V. C.Bs Selection

C.B	Max. FLA (A)	C.B rating (A)	Max. Fault (kA)	Rated Interruption Capacity (kA)
CB1	150.2	225	3.57	8.8
CB5	19	30	7.8	8.8
CB6	125.6	200	5.85	8.8
CB8	32	40	7.73	8.8
CB9	157.5	200	5.33	8.8
CB13	693.9	1200	5.78	8.8
CB14-121kV	7.3	20	20.87	31.5
CB G1	171.3	225	3.19	8.8
CB G2	174.6	225	3.5	8.8
CB WTG	94.8	200	4.43	8.8

3. Protection impacts and requirements in system with DGs

3.1 DG Impact on Fault Current Level: It was outlined that DG has great impacts to S.C levels and reasons for this difference in fault level between different topologies were mentioned in the introduction. To show clearly the impact of DG to fault levels it is helpful to compare fault current level in different configurations with respect to (w.r.t) the fault levels for the system without DGs as shown in Figure 2.



(a) (b)

Figure 2. % of fault magnitude (3ph, 1ph) for all nodes respects to fault currents of system without DGs: (a) config. 2 (PG+ All DGs), (b) Config. 5 (IS+ All DGs-DG1)

The following important notes are provided from Table 6 and Figure 2:

1-It is clear that topology 2 (PG+All DGs) has the greatest fault percentage among all topologies, that's due to the fault level is dependent on the MVAs.c of the source, and as this topology contains main power grid and all DGs so it has the largest MVAs.c and hence largest fault level. As a result of that we should design different system component (cable, C.B, Buses CT, …) capacity rating to withstand ,with a safe margin, this highest fault current as presented in section 2.2.

2-It is observed that 1-phase fault is greater than 3Phase fault in all configurations contain DG, that's because DG has a greater one phase fault current.

Table 6 and Figure 2 show only the impact of DGs of fault level, but DGs have other impacts on the protection system. Generally these impacts on protection system depend on DG penetration level, connection point to distribution networks and DG type and can be summarized in the following points (Andrés et al, 2012):

1- Difference in fault levels.

2-Bidirectional power flow due to high penetration, leads to undesired performance of protective devices if conventional protection technique is still used (Andrés et al, 2012; N. Schaefer et al, 2010; Muhammad et al, 2013).

3-Un detectable faults or false trip protective devices.

4-Lose of coordination.

5-Interruption devices damage may occur as a result of fault current increase to values greater than interruption capacity of devices-as devices were sized to system fault level without DG.

6-single phase fault greater than three phase fault due to DG have greater one phase fault current (as shown in above results).

Table 6. Average change in fault current w.r.t system without DG

Configuration	3Ph (kA)	1Ph (kA)
1 PG Only	100%	100%
2 PG+ All DGs	136.96%	185.40%
3 IS+ All DGs	51.50%	86.10%
4 IS+ no WTG	53.86%	93.79%
5 IS+ no Syn G1	32.10%	51.63%
6 IS+ no Syn G2	30.84%	44.35%

3.2 Protection Requirement in System with DG: As a result of these impacts, the protection technique which used for system with DGs should have the following requirements:

1-The ability to respond to both mode of operations (grid connected and Islanded), as if a fault occurs in the utility grid the desired response is to isolate the MG to operate it in autonomous mode, but if fault is happened within the MG the desired response is to disconnect as little areas of MG as possible to avoid unnecessary power outage (Andrés et al, 2012).

2-Achieving protection coordination, which can be understood: protection coordination is to adjust the protection system such that each protective device has to perform its primary function as quick as possible but in case it fails it should be backed up by the nearest hierarchical device, so protection coordination scheme seems to be good when it has the ability to disconnect as little as possible of system when faults happen (Waleed et al, 2013). Coordination between C.Bs depends on type, size and location of DG in the distribution network (Ehsan et al, 2010; Muhammad et al, 2013).

4. Adaptive OC Protection in System with DGs

This section illustrates adaptive protection method to overcome challenges emerged from DG impacts on protection system performance and on relays response. Basically relay settings must be continuously adapted to ensure that the microgrid is totally protected among different topologies. Therefore adaptive protection can be defined as "an online technique that continuously updating relays settings with respect to system configurations change in a timely manner using communication or communication-less means" (Alexandre et al, 2010). Relays coordination in power system is a tedious and time-consuming task, so adaptive protection idea is to deal with OC relays coordination in an online manner (Abdelaziz et al, 2002).

The idea of adaptive here depends on calculating the settings for all relays in different configurations. Basically, there is a percentage of fault level variation among different configurations due to difference MVAs.c in each configuration, and this percentage of variation is considered the same for all nodes. So, it is not required to run S.C analysis at all nodes in each configuration. However it is sufficient to calculate fault current at only one node in each configuration and compare it with the fault at the same node in the configuration without DG, to get percentage of fault level variation, and this percentage of fault level variation will be applied to all nodes. Therefore, by knowing relays settings in configuration without DG and percentage of fault variation, relays parameters in different configurations can be recalculated (Andrés et al., 2012).

Technical requirements for a practical implementation of adaptive MG protection system are as following (Alexandre et al, 2010):

1- Using numerical DOCR as the (electromechanical and solid state) relays aren't applicable, as they do not provide the flexibility to change the trip settings and they don't have current direction sensitivity feature.

2- Numerical DOCR relays must have multi settings groups that can be parameterized (automatically or manually) locally or remotely.

3-Using communication network such that individual relays can communicate and exchange information with a central computer quickly and reliably to guarantee optimum performance.

Adaptive protection system that satisfies these requirements is characterized by high investment cost in comparison to a conventional protection system. But separate cost-benefit analysis in case of MG concludes that operating costs over a system lifetime and benefit will be corresponded to a reduced outage time and opportunity loss (Alexandre et al, 2010).

5. Adaptive Protection Scheme Results

Based on a complete detailed system study in all configurations, it has been found that the best coordination method to apply, is adjusting units 50 (relays high set OC) only for trip when a fault in the local bus occurred, and make back up only with 51 units (relays low set OC) (Andrés et al., 2012). For verification the studied scheme results, the following steps were done:

1- Figure 1 represents the system case study which is a part of IEEE 13 node test feeder which is a radial test feeder, and all system data are given in (W.H. Kersting, 2001).

2- Building the case study model presented in (Andrés et al,2012) on ETAP but with some edits :
2.1- uniform all T.Ls in our model to be as the T.L between nodes (632-671) which is (3-phase, 4wire, 2000ft, ACSR (Aluminum Conductor Steel Reinforced), 556.5AWG) (W.H. Kersting, 2001).
2.2- Upgrading DG2 rating from 0.5MW to 1.2MW.
3- Using ETAP S.C. module to perform maximum S.C. analysis to design or select breaking or S.C. withstand capacities for different system parameters (C.Bs, Cable, T.Ls, Buses, and Switches). Really we perform max. S.C. analysis only in configuration#2 (PG+ all DGs) as it contains all sources so the largest MVAs.c, so largest faults among all configurations, as shown in Figure 2 and Table 6. This design criterion ensures that all system components withstand without damage any S.C. values in any topology. Samples of system parameters max. S.C. seen and rated capacity are shown in Table3 for switches, Table 4 for CTs and Table 5 for C.Bs.
4- Not only the max. S.C. current but also the max. FLA must be considered when sizing system parameters. Max. FLA seen by system components can be obtained using ETAP load flow (L.F) module, L.F results can be shown in Table 3 for switches, Table 4 for CTs and Table 5 for C.Bs. Max. FLA may be existed in any configuration except configurations that contain all DGs in service i.e. except configurations (PG+ All DGs and IS+ All DGs) as shown in Table 7, that's due to load sharing among all sources in the system, as DGs connection at load area reduce current drawn from main utility so reducing current in T&D network.

Table 7. Samples of FLA seen by system parameters in different configurations

Relay	C.T	C.B	#1 PG only	#2 PG +all DGs	#3 Is+ all DGs	#4 Is+ no WTG	#5 Is+ no Syn1	#6 Is+ no Syn2
R G1	CT g1	C.B g1	0	26.1	26.1	26.1	26.1	171.4
R1	CT1	C.B1	26.1	0	0	0	26.1	150.2
R6	CT6	C.B6	125.6	108.8	108.8	124.3	108.8	110.6
R G2	CT g2	C.B g2	0	46.8	148.1	174.6	169.3	0
R12	CT12	C.B12	202.3	101.7	0	0	0	0

5- Using ETAP S.C. module and load flow (L.F) module to perform minimum S.C. analysis and L.F analysis, respectively. These two analyses are done separately for each configuration to adjust relays settings (high set O.C & Low set O.C) as will be shown in section (5.1).
6- Using ETAP star coordination module to get relays curves coordination to check the response of adaptive method as will be shown in section (5.2).

5.1 Relays Settings in Different Configurations: In order to get a well coordinated protective system, it is required that all faults, abnormal operating conditions and system configurations must be pre-determined. The relays response will be satisfactory under these predetermined conditions. However if a scenario arises which is not taken in the previous consideration, the protection system behavior will not be satisfactory and system security will be in risk. Furthermore, it is impossible to determine the relay settings, which would be optimal for all abnormal and normal operating conditions (A.Y. Abdelaziz et al, 2002). Sample of relay settings in different configurations are presented in shown in Figure 3 and Table 8.

Table 8. Sample of relays settings in different configurations

Configurations	Relay 7				Relay DG2			
	I>	TDS	I>>	Delay S	I>	TDS	I>>	Delay S
1 PG Only	251.2	11	2695	0	Out of sevice			
2 PG+All DGs	217.6	2	500	0.2	93.6	26.07	1075	0.15
3 Is+All DGs	217.6	2	500	0.2	192.53	10	1075	0.1
4 Is+No WTG	248.6	20	1910	0.2	349.2	2	1050	0.2
5 Is+No Syn1	217.6	7	1000	0.1	388.6	7	1070	0.5
6 Is+No Syn2	221.2	2	520	0.06	Out of service			

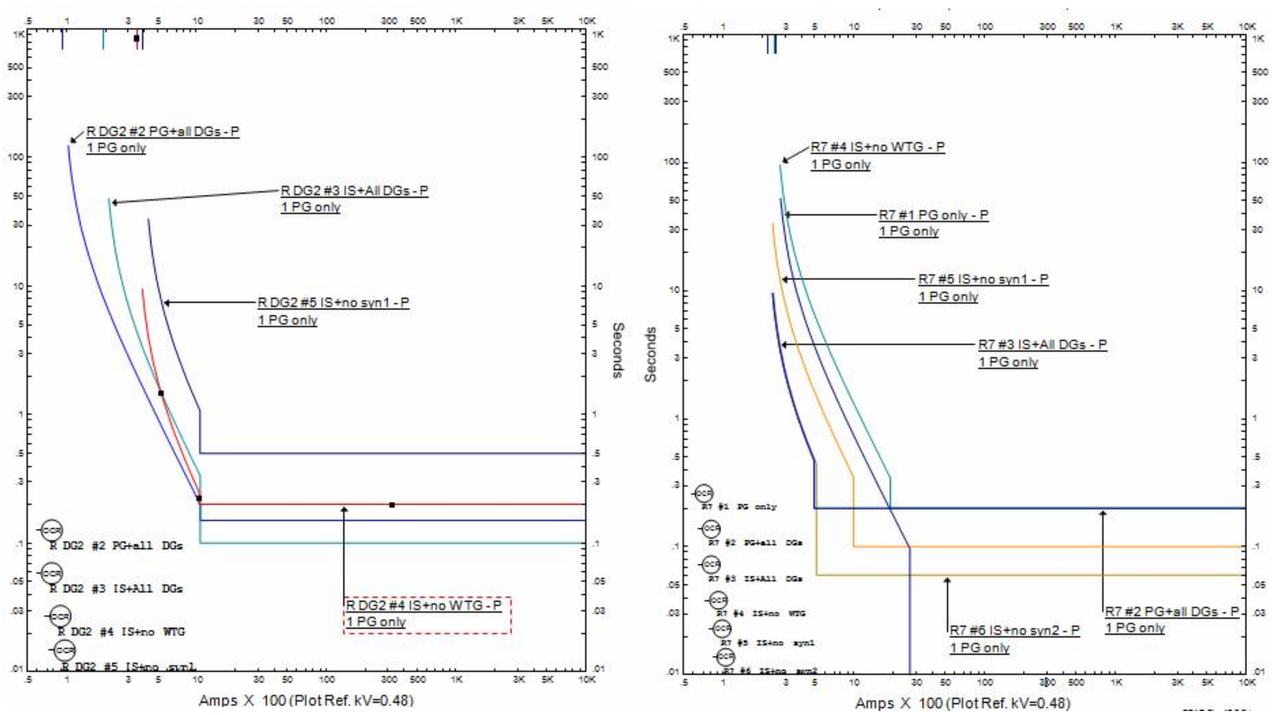
I>: Low set OC for OC protection, which take a value within (1.05 to 1.2) x FLA.

I>>: High set OC for protection against S.C. basically each relay is required to trip only for fault in the adjacent bus for example (Relay R6 in Fig.1 required to trip for fault at Bus675 and not required to trip for fault at Bus692 or any other faulted Bus). So this setting is selected, if it possible, to be lower than fault at the adjacent bus to a certain relay and higher than fault seen by the same relay due to fault at any other Bus.

Time Dial Setting (TDS): Represent OC trip curve for a relay, is selected to make relay TCC shape is accepted (i.e. connecting OC setting with S.C setting in an accepted view as shown in Figure 4).

Delay in seconds: is selected by taking CTI (Coordination Time Interval) in consideration.CTI can be seen as a certain time interval which should be maintained between protective devices curves to ensure selectivity. Without adequate CTI, protective devices could trip incorrectly.

CTI can be calculated as [CTI= C.B operating time 0.08 s + Relay disc travel (0.1 s for electro-mechanical relays only) + Relay setting error 0.12 s= 0.2 for static relays, as static relays have no significant overtravel) (IEEE Std 242,2001). Instantaneous OC relays as in Chapter 4 of (IEEE Std 242,2001) are operated without any time delay , relay operating time for in the range of (0.5 to 2 cycles) i.e.(0.01s to 0.04s for 50 Hz frequency). If CTI can be seen also as (C.B operating time + relay operating time), so CTI will be within range of (0.09 s to 0.12 s).

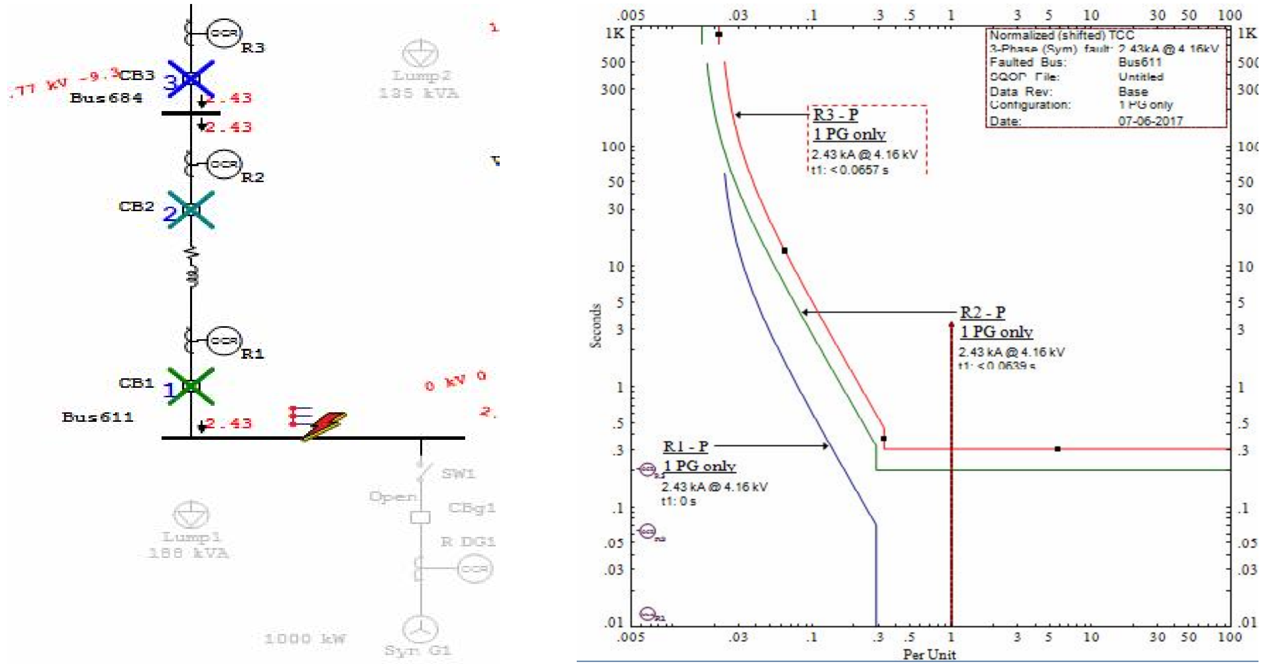


(a) (b)

Figure 3. Relays setting in different configurations: (a) R7, (b) R DG2

5.2 Coordination Results in Different Configurations: After calculation of optimal setting for different relays, these settings must be delivered to the corresponding relays via communication or communication-less techniques. Additionally, relay settings must be updated in time once the MG operation configurations are changed (Hengwei et al, 2016). Hereafter sample of coordination results for a fault at different buses among variable configurations will be proposed.

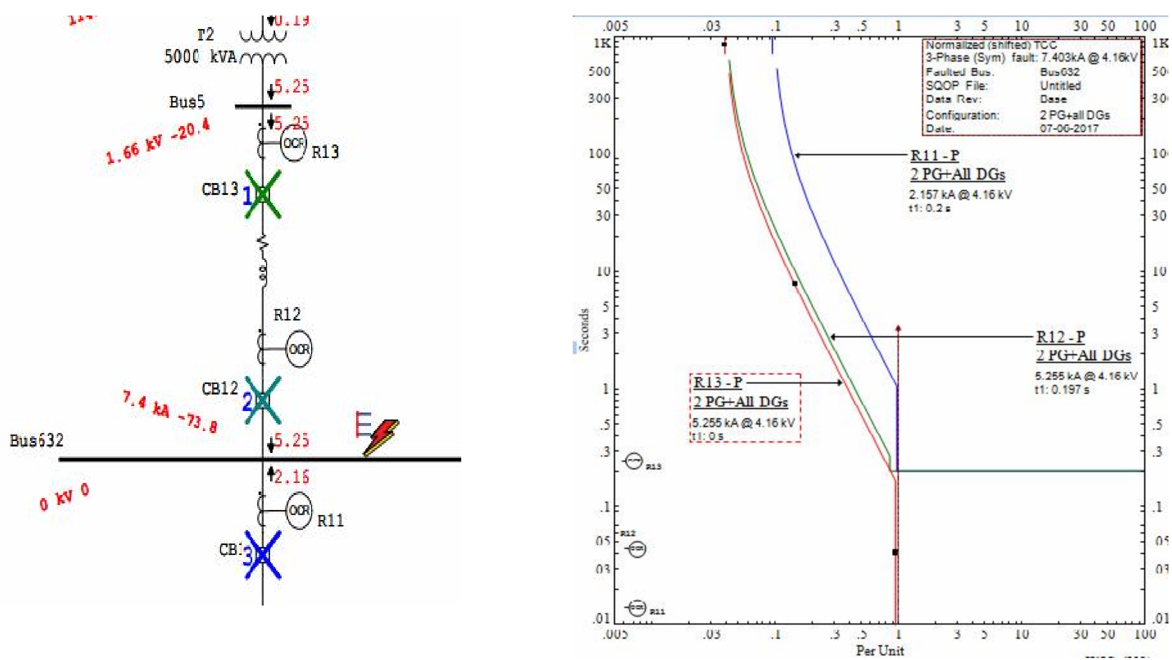
5.2.1 Configuration 1 (PG-only) Results: Configuration 1 represents the radial case as there is no any DG, and hence the power flow is unidirectional from main grid to downstream system components, so relays trip sequences must be hierarchically. For example for a fault at Bus 611,the required trip sequence is: R1 trip first but if it fails it should be backed up by R2 after that R3 and so on upward to the main grid as shown in Figure 4.



(a) **(b)**

Figure 4. Fault at Bus 611 for config. 1(PG only): (a) Operating sequence One Line Diagram (OLD), (b) Time Current Characteristics (TCC)

5.2.2 Configuration 2 (PG+All DGs) Results: In config. 2, the main grid plus all DGs are existed, so a bidirectional power flow will be occurred. So that in the case of fault the relays upward and downward the faulted bus should trip to disconnect the fault .For example ,when a fault at bus 632, relays (upward R12 and downward R11) the faulted bus required to trip as shown in Figure 5. Basically R12 is required to trip before R13 but it is impossible to determine the relay settings, which would be optimal for all abnormal and normal operating conditions as mentioned in (A.Y. Abdelaziz et al, 2002).



(a) (b)

Figure 5. Fault at Bus 632 for Config. 2 (PG +All DGs): (a) Operating sequence One Line Diagram (OLD), (b) Time Current Characteristics (TCC)

6. Conclusion

Adaptive OC protection technique based on system topological change for a distribution system with DG has been proposed. Results show that this protection scheme works well for MG and it is an effective tool to deal with protection issues related to DG penetration, as it success to preserve protection coordination between relays among different system configurations. The above work shows that the best coordination method is adjusting units 50 (relays high set O.C) to trip only when a fault in the local bus occurred, and make back up only with 51 units (relays low set O.C).For future work adaptive OC protection will be applied for the same system case study, but after converting it from radial to ring and obtaining results simulated to that are presented in this paper.

Nomenclature

DG	Distributed Generator.
MG	Micro-Grids.
MGCC	MG Central Controller.
DOCR	Directional OC Relay.
MGCPU	MG Central Protection Unit.
FCL	Fault Current Limiter.
BIL	Basic Insulation Level.

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