Mansoura Engineering Journal, (MEJ), Vol. 35, No. 1, March 2010

Acceptable DG Capacity for Radial Distribution System Based on Traditional Protection Scheme

السعة المقبولة من التوليد الموزع خلال شبكات التوزيع فى إطار نظم الحماية التقليدية

M. S. Kandil **M. G. Osman** **M. M. El-Saadawi** **M. A. Saead**

Dept. of Electrical Engineering
Faculty of Engineering
Mansoura University

ملخص البحث:

إن من طبيعة شبكات التوزيع الكهربائية التقليدية سريان القدرة فى اتجاه واحد . وهذه الشبكات يتم حمايتها بوسائل حماية بسيطة مثل المتممات ضد زيادة التيار، المصهرات ومعيدات التوصيل الأتوماتيكية. ويؤدى إضافة وحدات التوليد الموزع لشبكات التوزيع إلى العديد من المزايا لكل من المستهلك وشبكات التوزيع ولكن فى نفس الوقت لايمكن إغفال بعض الجوانب السلبية له، فعلى سبيل المثال ، سيؤثر اضافة هذه الوحدات على طبيعة الشبكة نفسها وبالتالى سيتأثر التنسيق بين اجهزة الحماية المختلفة. ولحل هذه المشكلة تحديدا فإن الاتجاهات البحثية تقترح أسلوبين مختلفين لمعالجة هذه المشكلة: الأسلوب الأول هو تغيير كامل لنظام الحماية؛ الأسلوب الثاني هو تحديد أقصى مساهمة من وحدات التوليد الموزع بشرط الحفاظ على التنسيق بين أجهزة الحماية كما هو بدون تغيير. الأسلوب الثانى يصلح كحل ابتدالى لبدء اضافة وحدات التوليد الموزع فى الدول النامية لأنه يوفر الوقت والمال.

هذا البحث يقدم إطارا مقترحا لكيفية تحديد أقصى حجم يمكن ادخاله من وحدات التوليد الموزع على شبكة توزيع بشرط الحفاظ على التنسيق بين أجهزة الحماية كما هو بدون تغيير. وتم اختبار هذا الاطار على شبكة توزيع بسيطة باستخدام الماتلاب سيمولينك وتحليل النتائج للتأكد من صحة الاطار المقترح.

Abstract

Traditional electric distribution systems are radial in nature. These networks are protected by very simple protection devices such as over-current relays, fuses, and reclosers. Recent trends in distributed generation (DG) and its useful advantages perfectly can be achieved while the relevant concerns are deliberately taken into account. For example, penetration of DG disturbs the radial nature of traditional distribution networks. Therefore, protection coordination will be changed in some cases, and in some other cases it will be lost which is very costly in that two cases. In developed countries it could be cost effective if adding DGs to the network keeping the traditional protection system unchanged. To tackle that point of research, authors proposed technique to maintain the old protective devices coordination unchanged up to a specific DG penetration level.

In this paper, a framework is presented for determining the maximum capacity of DG penetration level to keep traditional protection scheme for distribution network unchanged. Applying that framework in the developing countries could save money and time during the integration of DGs to the network on a large scale based on country regulation. The proposed framework is implemented on a simple distribution network using MATLAB SIMULINK and finally the numerical results are presented in order to validate the suggested framework.

Keywords: ***Distributed Generation, Protection, Coordination, Autorecloser, Fuse.***

Accepted March 31, 2010.

1. Introduction

The integration of Distributed Generation (DG) into power systems can offer major benefits such as increasing system reliability, enhancing emergency backup during sustained utility outages, reducing voltage sags and adding potential utility capacity deferrals [1]. However, besides its various benefits, distributed generation can cause various negative impacts including their effect on system operation and protection [1-3]. Many protection issues including: coordination of protective devices [4-7], islanding problem, failure in impedance relays [5], and short circuit levels have to be analyzed. Among these issues, loss of protection coordination is a major problem as it directly affects continuity and reliability of service [4]. In the last decade many researches have discussed the coordination problem after adding DG resources. Hadjsaid et al. [2] show through a simple example that fault currents through protective devices would change after introduction of DG. They further suggest checking protection selectivity for each new integration of DG. However, this solution would work only if DG penetration is low. Menon [3] introduced a theoretical review on the coordination problem while investigating the islanding problem. Girgis and Brahma [4] explored the effect of DG on protective device coordination such as fuse-fuse, fuse-recloser and relay-relay, depending on size and placement of DG. The authors discussed the loss of coordination occurrence, when the protective device pair sees the same fault current for a fault downstream as well as for a fault upstream. Nimpitiwan et al. [5] introduced an artificial optimization method for protective relays coordination using ant colony optimization; the paper discussed only relay-relay coordination. Brahma and Girgis [6] proposed an adaptive protection scheme offering a solution to the problem that is independent of size, number, and placement of DG in the distribution system but the scheme did not work well for systems with low DG penetration. El-Saadawi [7] investigated the coordination between fuses and reclosers in a distribution system and developed a new Simulink model for recloser and fuse that can be used for coordination studies. Mäki, et al. [8] introduced a simple solution for relay-relay and recloser-relay coordination problem. They suggested disconnection DG during the dead time of the recloser. Seegers et al. [9] have investigated some protection issues include: protective device coordination problems due to infeed and bi-directional current flow. Kumpulainen and Kauhaniemi [10] introduced a solution for recloser coordination problem by increasing the dead time for recloser until the island protection disconnects the DG. Doyle [11] has investigated the changes in fault levels with the addition of DG at the various locations. Häger et al. [12] concluded that the presence of DG greatly affects the clearing time of protective devices installed at the upstream distribution feeders. Gómez and Morcos [13] proposed a method to solve the coordination problem between under voltage relay and over current relay in DG environment, but the authors did not discuss the recloser or fuse coordination. Jäger et al. [14], discussed the relay coordination problem, and concluded that increasing the DG penetration into distribution networks leads to higher short circuit level and shorter delay times, so relays may be get faster. Selman and Ride [15], concluded that there is a significantly effect of DG on the clearing time of protective devices installed at distribution feeders. Chaitusaney and Yokoyama [16], derived a set of equations used to determine the maximum DG penetration while the existing protection scheme can be maintained.

Based on that review, it looks that there are two techniques to study the impact of integrating DGs on the protective devices coordination. First technique is to change the whole protection system; second technique is to maintain the old protective devices coordination unchanged up to a specific DG penetration level. At that research authors study the impact of integrating DGs on the protective devices coordination using the second technique. Authors choose that technique as an inexpensive technique when studying that impact in the developing countries distribution networks.

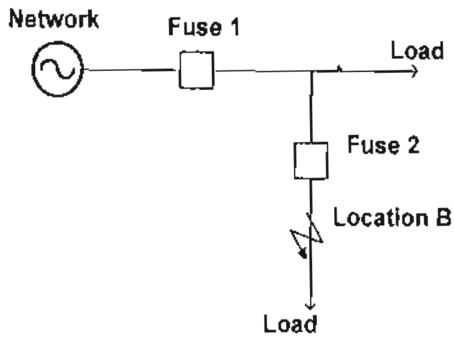
The paper is organized as follows: section 2 represents coordination problem with and without DG, and discusses the most important protective devices coordination. Section 3 introduces the proposed framework to determine the acceptable DG capacity for distribution system based on traditional protection scheme. Section 4 represents the system modeling. In section 5, the proposed framework is applied to a part of a distribution system, a fault analysis is done and the impact of DG penetration level on protective devices coordination is investigated for different numerical cases.

2. Coordination Problem

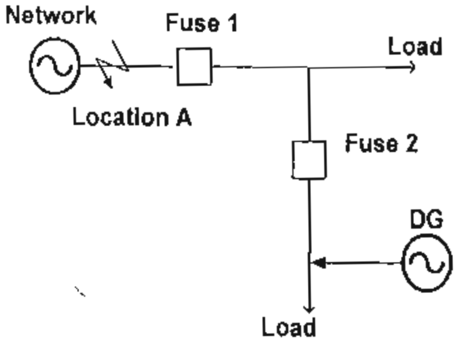
Conventional distribution system protection is based on time-over-current relays, fuses and reclosers that are coordinated with each other, so that the device near the fault clears the fault first to minimize the duration and extent of interruptions. This coordination problem in distribution networks includes relay-fuse, fuse-fuse, recloser-fuse, recloser-relay, relay-relay, recloser- sectionalizer and recloser-sectionalizer-fuse [17]. In the following subsections we will discuss some of the important protective devices coordination.

2.1 Fuse-Fuse Coordination

Figure 1-a, shows a fuse-fuse coordination scheme without DG, when a fault occurs at location B, fuse 1 and fuse 2 would see the same fault current injected by the utility grid. For conventional distribution system fuse 2 should act faster than fuse 1 to isolate as minimum part of the system as possible. This coordination scheme will not fit well after adding DG. For a fault at location A after adding DG, both fuses see the same fault current as shown in Fig. 1-b. In this case fuse 1 should act faster than fuse 2 which contrasts with the original fuse-fuse coordination before adding DG. It is clear that the fuse-fuse coordination requirement for an upstream fault in the presence of DG is in contradiction with the fuse coordination requirement in the absence of DG.



(1-a)



(1-b)

Fig.1 Fuse-Fuse Coordination Scheme

2.2 Recloser-Fuse Coordination

In rural areas; circuit protection is often done by the coordination of fuses and reclosers [3]. Figure 2, shows a recloser-fuse coordination scheme before and after adding DG. For a fault occurring at location A, the recloser is normally programmed to make two short reclosing attempts, and if the fault persists, it makes a longer reclosing attempt before it goes to lock out. In a reliable system the fuse would operate during the long reclosing time of the recloser so that power continues supplying the portion of the line between the fuse and the recloser as explained by Fig. 2-a.

Integrating DG to the system (Fig.2-b) increases the short circuit current passing through the fuse. The fuse settings may be changed and presence of DG may prevent the successful operation of the recloser.

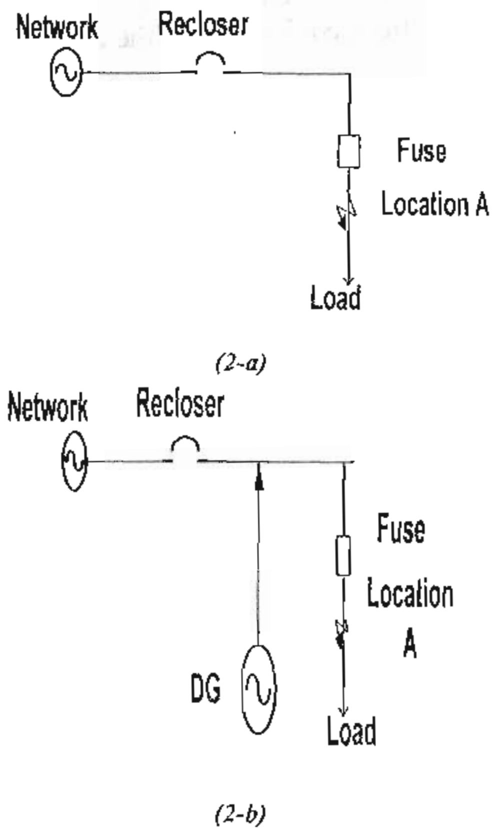


Fig. 2 Recloser-Fuse Coordination before and after Adding DG

2.3. Relay-Relay Coordination

Figure 3-a, shows a relay-relay coordination scheme without DG. Circuit breakers CB1 and CB2, are controlled by relays R1 and R2, respectively. For a fault occurring at location B, the fault current passes through the two breakers, and CB2 is designed to trip before CB1. For a fault at location A after adding DG, the fault current injected by the DG passes through the two breakers (Fig. 3-b). In this case, CB1 trips before CB2 which contrast with the coordination scheme of the existing conventional system.

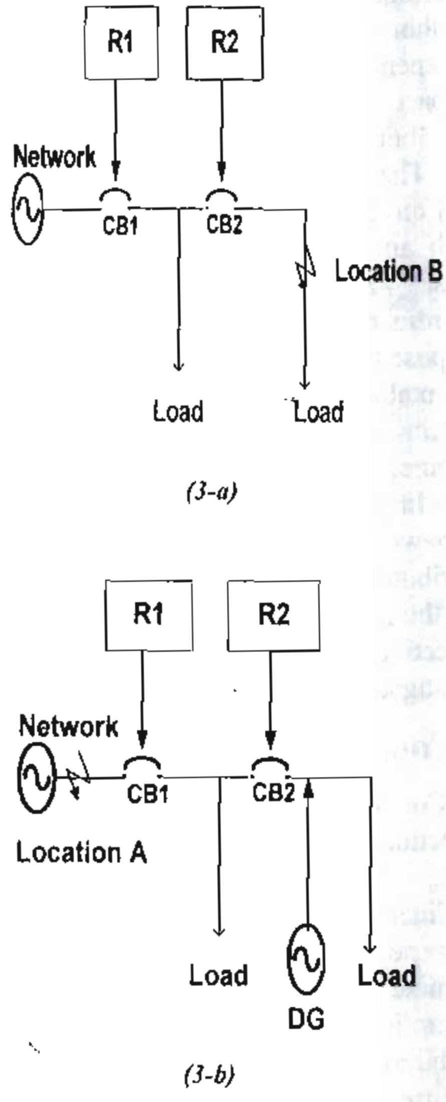


Fig. 3 Relay -Relay Coordination

3. Proposed Framework

A framework is proposed to determine the maximum DG penetration level that maintains the coordination unchanged. This framework is based on a simulation study for a system using Matlab/Simulink environment. Figure 4 shows a flow chart for the proposed framework.

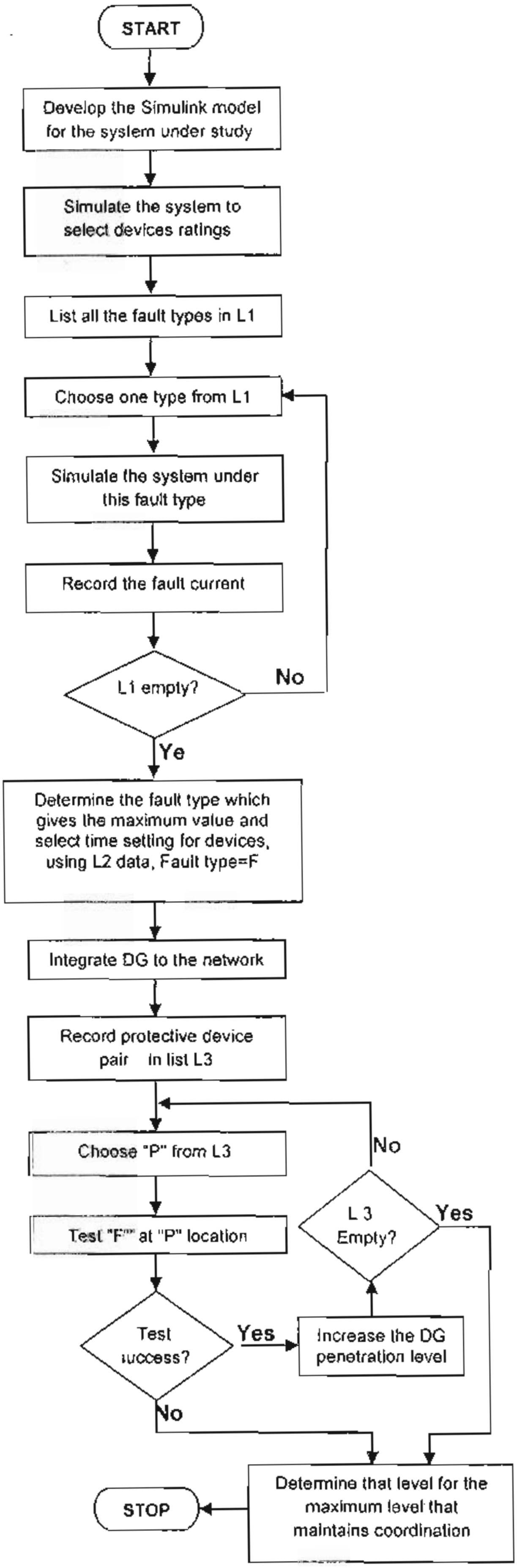


Fig. 4 Flow Chart of the Proposed Methodology

4. System Modeling

In this research Simulink and SimPowerSystems (SPS) toolbox of Matlab are used to model the system [18, 19]. Simulink is used as an environment to simulate the whole system, whereas SPS is used to simulate the individual components of the system such as source, transformer, transmission line and load. However, not all the power system components can be modeled using SPS toolbox [19]. There is not any element to represent the fuse or recloser. SPS models only the switch element (ideal switch, breaker). The switch model can work in two ways; first it could be set to a specific time to respond (internal control). Second it could be set to respond to external signal which has to be achieved using external control circuit. To simulate the operation of different protective devices using the switch model, an external control circuit is designed. This means that the switch model responds externally. That control circuit determines the required time to activate a protective device according to its TCC (Time Current Curves) and sends the open signal to the switch that opens the circuit.

The structure of the simulated protective device using external control circuit and switch model is shown in Figure 5, where Ii and Io are the currents passing through the protective device. The TCC curves for all fuse and recloser used in the feeder are attached in a table inside the control circuit. The authors have designed control circuits for simulating the operation of different protective devices [7, 20]. In this study the developed models are used to simulate the operation of fuses, autoreclosers and relays.

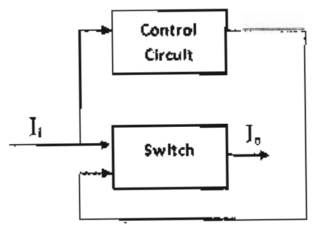


Fig. 5 Protective device model

5. Numerical Applications

The proposed framework is applied to a part of a distribution system, shown in Fig. 6. The test system is composed of a 3-phase 2.5 MVA, 11 KV source supplying through a primary feeder, a 3-phase 2.5 MVA, 11000/400 V distribution transformer connected to two secondaries ended with 7 loads. The parameters of the feeder and the secondaries and the load data are given in appendix A.

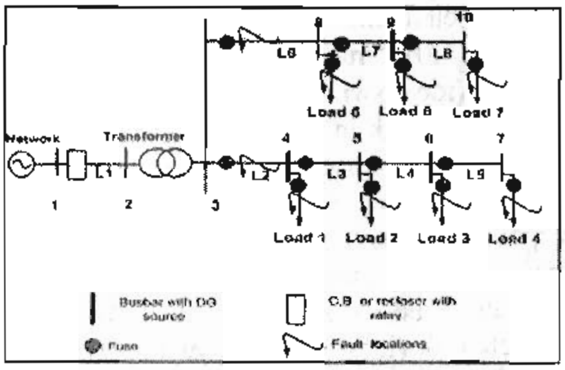


Fig.6 Schematic Diagram of the Test System

5.1 Developing the Simulink Model

The test system is modeled using Matlab Simulink. The network is represented by a three phase source and a transformer. The feeder is represented as a three phase transmission line. The previous components are represented in Simulink library as three phase source block; three phase two-winding transformer block and line block respectively. The fuse, recloser, and relay are represented by the models developed by the authors. Finally the DG resource is represented by a three phase source, according to reference [16].

5.2. Determination of Protective Devices Ratings

The system is simulated in normal case before adding any protective devices to measure the currents flow in each branch of the system. Based on those currents, the appropriate fuses minimum melting Time-Current characteristic curves rating is selected according to [21} and relays according to Appendix B. The over current relay used with C.B or recloser rated current is designed according to design rules in [17] and the rated current for the relay is 25 amps and selected CT ratio of 50/5. The fuses rated currents obtained from the simulation are shown in Table 1.

Table 1. Fuses Rated Currents

Fuse Number	Fuse Rating (A)
1	200
2	65
3	80
4	65
5	50
6	40
7	40
8	30
9	125
10	100
11	80
12	30
13	50
14	25

5.3. Fault Analysis before Adding DG

A short circuit analysis is performed to determine the minimum and maximum short circuit currents. The minimum short circuit current denotes the minimum operating current for the protective devices while the maximum gives the maximum permissible current passing through it. A line to ground, line to line, line to line to ground ànd three phase faults were applied at different fault locations as shown in figure 6. The fault duration is 0.2 seconds. In every case a three phase fault gives the maximum short circuit current value. Based on the short circuit analysis performed, the appropriate time settings for all protective devices coordination are chosen. The minimum melting time for the fuse is selected according to [21] and the operating time for the relay used with C.B or recloser at the beginning of the feeder is taken as 0.2 seconds. The results are shown in Table 2.

Table 2. Results of Fault Analysis before Adding DG

Bus Number	Fault currents before adding DG	
	Min S.C (A)	Max S.C (A)
2	181	200
3	5000	5500
4	2200	2400
5	1000	1200
6	500	600
7	400	500
8	2200	2400
9	800	1000
10	480	550

5.4. Coordination Test

For each protective device pair, the coordination test has been performed by applying a three phase fault as it gives the maximum fault current at different locations shown in figure 6. The simulation time is selected to be 0.5 seconds and the fault duration is 0.2 seconds.

- ***Relay-fuse1 coordination***

The fault is applied at the beginning of line 2. Fuse 1 and the relay see the same fault current (5500 amps), the primary device responsible for this fault is the fuse and the relay is the backup. The fuse operates correctly and clears the fault after minimum melting time of 0.03 seconds. However if the fuse does not operate correctly the relay clears the fault after 0.2 seconds. So , if the primary device only operates correctly for fault case to clear the fault, the coordination is succeed but if the primary and backup device operate for a fault case, the coordination is fail. Similarly, in case of Relay-fuse9

- ***Recloser- fuse 1, coordination***

The recloser has an opening and closing times. For simplicity 0.2 seconds was selected for recloser opening and closing times. The fuse operates successfully to clear the fault. The test is repeated 9 times at fault locations as shown in figure 6 and before adding DG, all coordination case studies is success as the classic system is designed with coordination interval between every protective device pair depending upon the minimum and maximum fault current passing through this pair. The results are shown in Table 3.

Table 3 Coordination Test Results without DG

Protective devices pair	Fault location	Without DG
Relay-FUSE 1	F1	Success
Relay-FUSE 9	F2	Success
Recloser-FUSE 1	F1	Success
Recloser-FUSE 9	F2	Success
FUSE 1- FUSE 2	F3	Success
FUSE 3- FUSE 4	F4	Success
FUSE 5- FUSE 6	F5	Success
FUSE 7- FUSE 8	F6	Success
FUSE 9- FUSE 10	F7	Success
FUSE 11- FUSE 12	F8	Success
FUSE 13- FUSE 14	F9	Success

5.5. Impact of DG Penetration Level

After adding DG, the protective devices coordination may success or not as the level of fault current is increased because the DG will contribute fault current in the protective device pair, if this contribution is small i.e. the penetration of DG level is small, the coordination interval between every protective device pair may be hold as the conventional system so the coordination in this case is success and vice versa.

5.5.1. Fault analysis after adding DG

After adding DG sources, a short circuit analysis is performed to investigate the DG contribution to fault currents and consequently their effect of protective devices pairs. The fault duration is 0.2 seconds. DG sources are added to buses 4, 6 and 9. The DG penetration level is increased in steps of 10%, 20%, 30%, 40% and 50% of total feeder rated power. Table 4 gives the results of this simulation.

5.5.2. Coordination test

A three phase fault is applied at different locations to test the coordination of each protective device after adding DG; the results are shown in Table 5.

- If the primary device only operates correctly for fault case to clear the fault, the coordination is succeed but if the primary and backup device operate for a fault case , the coordination is fail.
- In case of fuse7- fuse 8 coordination tests at location F6, if the DG penetration is small enough, 10 % for example, A 640 amps passes through the two fuses but fuse 8 is the primary protective device for this fault. It clears the fault in 0.04 seconds and operates correctly. As the DG penetration level increases up to 20%, this test is succeed but if the DG penetration level is 21%, the fault current causes the two fuses to operate as the coordination time interval decreases between the two fuses to 0.0022 seconds, i.e. fuse 8 disconnects after 0.0074 seconds and fuse 7 disconnects also after 0.0096 seconds.
- If the DG penetration level is large enough so the coordination interval between every protective device pair may not hold, so the coordination in this case is fail.
- Failure begins at the last protective devices as the short circuit current equals to the sum of all DGs sources and the network together.
- This failure is proportional to the DG penetration level and more DG penetration levels result in more coordination fail cases.
- DG penetration level up to 20 % of the feeder power holds the coordination unchanged but 21% of DG penetration level begins to change the coordination in a part of the system.
- The next change in the other parts depends on the DG contribution of fault current as shown in Table 5, the next case at 24% of DG penetration and so on.

Table 4. Results of Fault Analysis after Adding DG

Bus	Fault analysis results after adding DG									
	10%		20%		30%		40%		50%	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
2	184	205	190	240	215	300	260	330	300	380
3	4700	5500	5100	6000	5700	6500	6400	7000	6600	7300
4	2400	2700	2700	3100	3000	3400	3500	4000	3700	4200
5	1100	1400	1300	1500	1430	1650	1500	1800	1720	2000
6	650	760	740	820	860	1110	1250	1500	1430	1750
7	520	640	680	780	730	820	800	1030	900	1300
8	2200	2600	2500	2800	2700	2900	2800	3100	2950	3400
9	820	940	1000	1160	1050	1300	1200	1500	1600	1900
10	560	630	570	690	675	750	700	900	800	930

Table 5. Coordination Test Results with DG

Protective devices pair	FAULT Location	WITH DG							
		10%	15%	18%	20%	21%	22%	23%	24%
Relay-FUSE 1	F1	S	S	S	S	S	S	S	S
Relay-FUSE 2	F2	S	S	S	S	S	S	S	S
Recloser-FUSE 1	F1	S	S	S	S	S	S	S	S
Recloser-FUSE 2	F2	S	S	S	S	S	S	S	S
FUSE 1-FUSE 2	F3	S	S	S	S	S	S	S	S
FUSE 3- FUSE 4	F4	S	S	S	S	S	S	S	S
FUSE 5- FUSE 6	F5	S	S	S	S	S	S	S	S
FUSE 7- FUSE 8	F6	S	S	S	S	F	F	F	F
FUSE 9- FUSE 10	F7	S	S	S	S	S	S	S	S
FUSE 11- FUSE 12	F8	S	S	S	S	S	S	S	S
FUSE 13-FUSE 14	F9	S	S	S	S	S	S	S	F

S= Success F= Fail

6. Conclusion

Coordination between distribution protective devices can be disrupted with substantial penetration of distributed generation. There are two scenarios for solving this problem: change the setting of existing protective devices or determine the maximum DG penetration level that maintains the protective devices coordination unchanged. Locally in Egypt the DGs era is still new. This paper presents a method to determine the maximum DG penetration level that maintains the coordination unchanged based on simulation studies results.

Matlab/Simulink is used to model a system and detailed simulation is performed to obtain the level of DG at which coordination remains unchanged. Two control circuits for simulating the operation of both relay and recloser are designed, since there is not a single block to represent them in SimPowerSystems (SPS). Those proposed control circuits can be used for any other applications.

For the system under study the maximum allowable DG penetration level to maintain the protective devices coordination unchanged is 20% of rated network power.

This proposed technique is laying the ground for this kind of study on Egyptian distribution networks. It also, automates the process of testing the integration of DGs to distribution networks on their protection system. It guides the distribution engineers in developing countries on how to deal with this impact.

7. References

1. G. Pepermans, et al.,"*Distributed Generation: Definition, Benefits and Issues*", Energy Policy, Vol.33, Issue 6, April, 2005; pp. 787-798
2. N. Hadjsaid, J. Canard, and F. Dumas, "*Dispersed Generation Impact on Distribution Networks*" IEEE Computer Applications in Power, vol. 12, pp. 22–28, Apr. 1999.
3. V. V. Menon, "*A New Islanding Detection Technique For Distributed Generation*", Montana State University, January 2006.
4. A. Girgis, and S. Brahma, "*Effect of Distributed Generation on Protective Device Coordination in Distribution System*", Proc. Large Engineering Systems Conference, Halifax, NS, Canada, pp. 11-13, 2001.
5. N. Nimpitiwan, et al, "*Consequences of Fault Currents Contributed by Distributed Generation*", Report, Power Systems Engineering Research Center, June 2006.
6. S. Brahma, A. Girgis, "*Development of Adaptive Protection Scheme for Distribution Systems with High*

Penetration of Distributed Generation", *IEEE Transactions on Power Delivery*, Vol. 19, No. 1, January 2004.
7. M. M. El-Saadawi, "*Impact of Distributed Generation on Coordination of Protective Devices*", Mansoura Engineering Journal, (MEJ), Vol. 34, No 2, 2009
8. K. Mäki, S. Repo, P. Järventausta, "*Protection Issues Related to Distributed Generation In a Distribution Network Using Ring Operation Mode*", Nordic Wind Power Conference Chalmers University Of Technology, 1-2 March, 2004.
9. Working group D3, "*Impact of Distributed Resources on Distribution Relay Protection*", Report, IEEE – Power System Relay Committee, August 2004.
10. L. Kumpulainen, K. Kauhaniemi, "*Distributed Generation and Reclosing Coordination*", Nordic Distribution and Asset Management Conf. Espoo, 23-24 August, 2004.
11. M.T. Doyle, "*Reviewing the Impacts of Distributed Generation on Distribution System Protection*", IEEE Power Engineering Society, Vol.1, 2002.
12. M. Häger, F. Sollerkvist, M. Bollen, "*The Impact of Distributed Energy Resources on Distribution-System Protection*", Nordic Distribution and Asset Management Conference 2006 (Nordac), Stockholm, August 2006.
13. J. Carlos Gómez., M.M. Morcos, "*Coordination of Voltage Sag and Over current Protection in DG Systems*", IEEE Transactions on Power Delivery, Vol. 20, No. 1, January 2005.
14. J. Jäger, T. Keil, L. Shang, R. Krebs , "*New Protection Coordination Methods in the Presence of Distributed Generation*", 8th International Conf. on Developments in Power System Protection Amsterdam, Netherlands, 5-8 April 2004.
15. S. K. Salman, I. M. Rida, "*Investigating the Impact of Embedded Generation on Relay Settings of Utilities' Electrical Feeders*", IEEE Transactions on Power Delivery, Vol. 16, No. 2, April 2001.
16. S. Chaitusaney, A. Yokoyama, "*Impact of Protection Coordination on Sizes of Several Distributed Generation Sources*", The 7th International Power Engineering Conference, IPEC , Vol. 2 , 2005, pp.669 – 674
17. M. Gers and J. Holmes, "*Protection of Electricity Distribution Networks*" book, 2nd edition, The Institution of Electrical Engineers, UK, 2004.
18. "*Using Simulink*", the MathWorks, Inc., 2008
19. "*SimPowerSystems User's Guide*", The MathWorks, Inc., 2008
20. M. M. El-Saadawi, "*Modeling and Simulation of Protective Devices for Distributed Generation Applications*", International Journal of Distributed Energy Resources (under publication).
21. S&C electric company, available on line at: http://www.sandc.com/support/tccs_main.asp

8. Appendices

Appendix A
Test System Data [6]

- ***Feeder Parameters***

The length of the primary feeder is 10 Km and the length of the two secondaries is 6.5 Km with the following parameters: R= 0.125 Ω/Km, L= 0.293 mH/Km and C=0.286 μF/Km

- ***Load Data***

Table A.1. Load Data

Load Position	Value (KVA)
L1	30.88
L2	38.12
L3	24.56
L4	15.12
L5	43.86
L6	14.70
L7	10.08

Appendix B

Typical operating curves for an inverse-time relay [18]

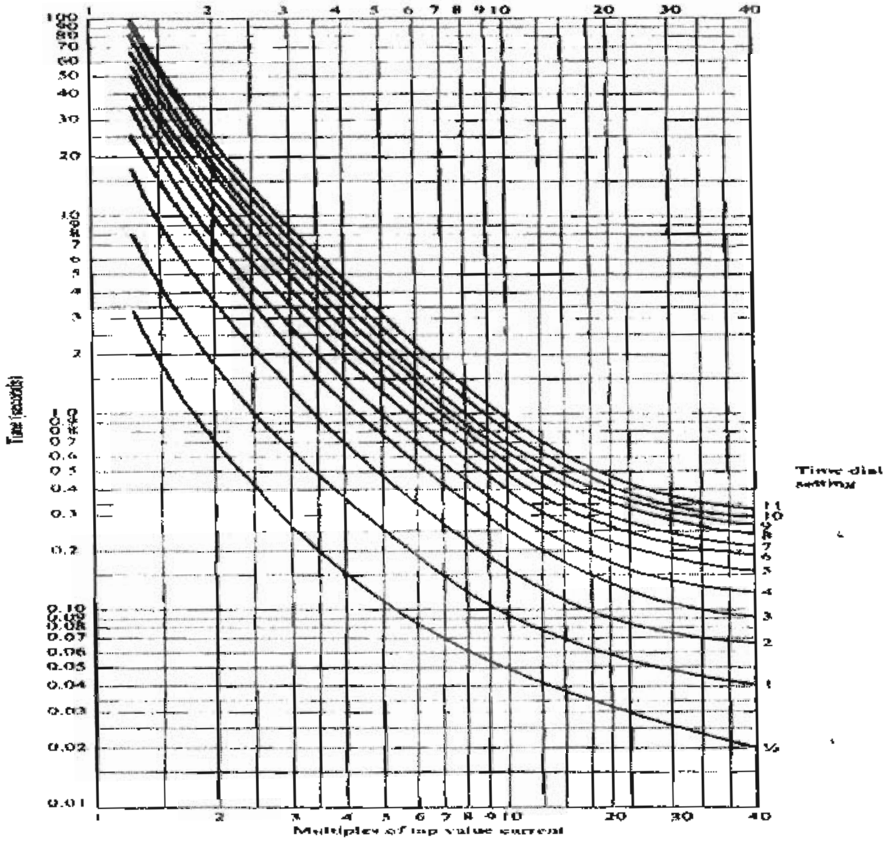


Fig. B.1 Inverse time Relay curves