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Distributed Generation Impacts on the Protection Systems in Distribution Networks

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***Abstract*— Traditional electric distribution systems (DSs) are radial in nature, and are supplied through a main source. These networks have a very simple protection system, and its implementation is also very simple, an easy protection strategy which is usually implemented using fuses (F), automatic circuit reclosers (ACR), and circuit breaker (CB), that are coordinated with each other is been used. So that the device nears the fault will clear the fault first and minimize the duration and extent of interruptions. It is so automated to safely clear faults and get customers backing service as quickly as possible. Recent developments in energy policies and prices have directed an increasing amount of interest at exploiting small energy resources which is commonly known as distributed generation (DG). In general, a DG provides several benefits to distribution network. Besides its various benefits, the DG does increase fault levels in the distribution system, change network radial configuration. Consequently it has influence on existing protection systems. The presence of DG tends to affect the protection system coordination. This paper presents an optimization based method to calculate maximum allowable capacity of a DG considering a set of constraints formulated to maintain protection system coordination, and feeder loss is also taken into account, with the developed methodology, the maximum DG capacity which does not provide adverse effects to the existing system.**

***Keywords*— ACR, CB, DG, coordination, Optimization.**

Nomenclature

DSs	electric distribution systems
F	Fuse.
ACR	Automatic circuit recloser.
CB	Circuit breaker.
DG	distributed generation
ACR S	Slow curve of Automatic circuit recloser.
ACR F	Fast curve of Automatic circuit recloser.
I_R	fault current seen by ACR
I_F	fault current seen by fuse.
I_S	fault current flowing from utility.
I_{DG}	fault current flowing from DG.
I_{FM}	current seen by fuse with the margin fault current from DG.
P_{DG}	Output of DG in MW.
P_{L1}	total line loss of the system with a DG, and
P_{L2}	total line loss of the system without DG.
TRf (I_S)	recloser fast curve operating time at I_S
MMTF (I_S+I_{DG})	fuse minimum melting time at (I_S+I_{DG}).
$I_{R,Pickup}$	Pick up setting current of reclose.
TRf (I_S+I_{DG})	recloser fast curve operating time at (I_S+I_{DG}).
LP	load point.
R	mid-line recloser.

I. INTRODUCTION

The advantages of DG are of both engineering and economic viewpoints. The advantageous applications of DG can be summarized as follows: backup generation, loss reduction, power quality improvement, grid expansion postponement, environmental concerns, peak load service, rural and remote application, combined heat and power generation, and financial and trading purposes [1], [2]. In the same way that distributed generators bring benefits, they have a potential of significant impact on the system and equipment operation in terms of steady-state operation, dynamic operation, reliability, power quality, stability, protection and safety for both costumer and electricity suppliers. In this paper, the focus will be on the impact of DG on system protection.

As the distribution systems have initially been built for simple one way power delivery, the penetration of DG currents results in not having a radial distribution network. They have a potential of significant impact on the system. Evidently, the short circuit current would be altered due to the contribution of DG. The unacceptable operation of protective devices may occur, since the protection coordination will be lost if the fault current flowing through any protective device is changed.

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Finally, this might lead to the large damage in system and the decrease in system reliability. This seems that DG brings about lots of problems. It is true that protective devices may need to be changed or have new settings. However, this requires large investment, and cannot be established in a short period.

II. Protection Coordination Of Traditional Distribution System

To protect system components and satisfy safety purpose, the protection devices must be installed along with the main and lateral feeders. In general, CB and ACR are designed to protect the system by disconnecting the circuit at the beginning and the middle as their locations on the main feeder. Besides, fuses are placed at the lateral feeders and are responsible for the lateral circuits. Showing protection devices, Fig.(1) depicts a sample of typical radial distribution feeder [3].

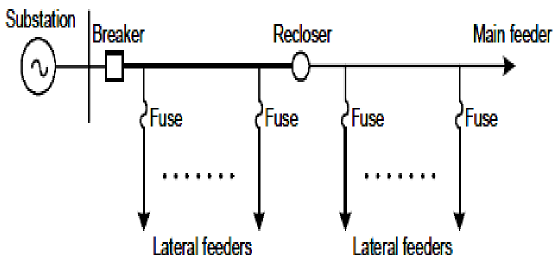

Fig. (1) Typical Radial distribution feeder[3]

There are two classes of utility system faults: temporary and permanent, since temporary faults constitute 70% to 80% of faults occurring in distribution system. The coordination scheme is normally determined according to individual specific topology of a distribution system, as well as various desired behaviors. As a typical distribution feeder in Fig.1, the traditional protection coordination could be, however, shown in Fig.(2) [4], [5]. It is a general coordination of CB, ACR, and a lateral fuse behind the ACR. The attitude here is that protection coordination should be able to confine the disconnected circuit as the smallest area when a fault takes place. This is to obtain the least electricity interruption. For example, when a fault takes place at the lateral feeder, ACR at fast mode should operate first to discriminate for the temporary fault, if the fault still exists(permanent fault), the lateral fuse will be blown up, and cause a permanent electricity outage.

However, if fuse fails to operate in this stage, ACR at slow mode can act as a backup protection later. To obtain this sequential operation, the fault current must comply with the minimum and maximum current shown in Fig.(2). Regarding circuit breaker, it will operate lastly as the whole backup protection when both ACR and fuse fail in their responsibility.

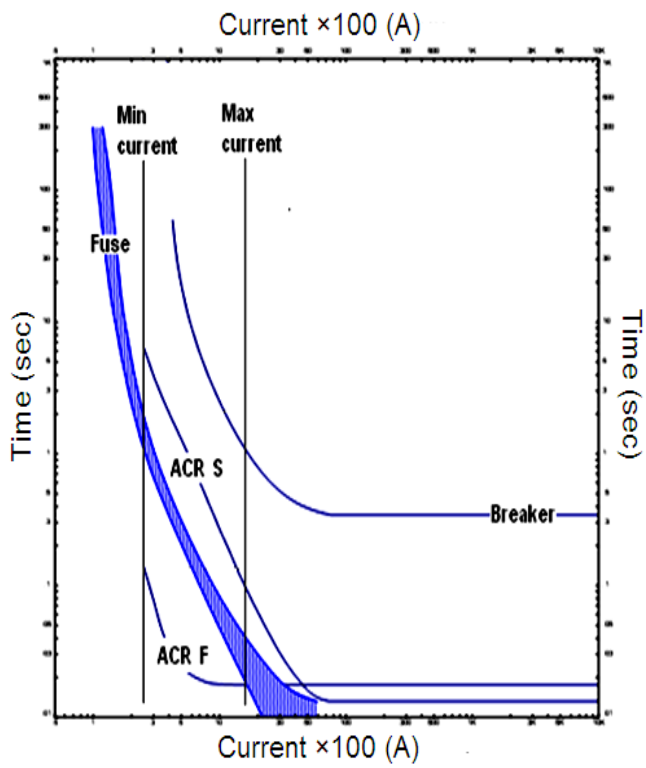

Fig. (2) Coordination between ACR, CB and fuse

III. Impact Of DG On Distribution System

The penetration of DG into distribution system will no longer maintain the radial characteristic of distribution feeders. Instead, the distribution system will be changed to be mesh configuration. The impact of fault current from DG depends on size and location of DG. According to the literature, a number of troublesome cases are caused by DG fault current. However, only fuse blowing and false tripping (sympathetic tripping) that are cited mostly will be briefly investigated here. The examples of these two cases can be generally illustrated in Fig.(3) and Fig.(4) [6], [7].

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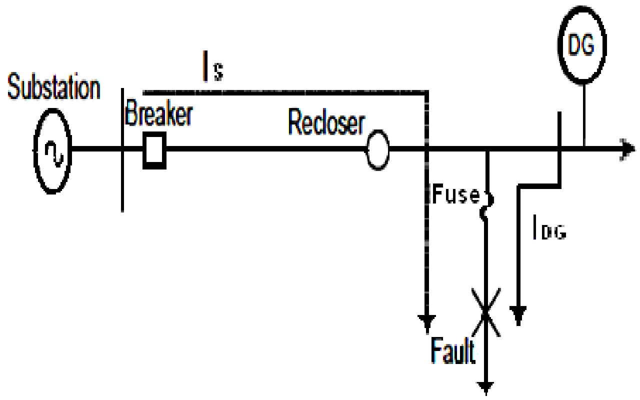

Fig. (3) Fuse blowing[3]

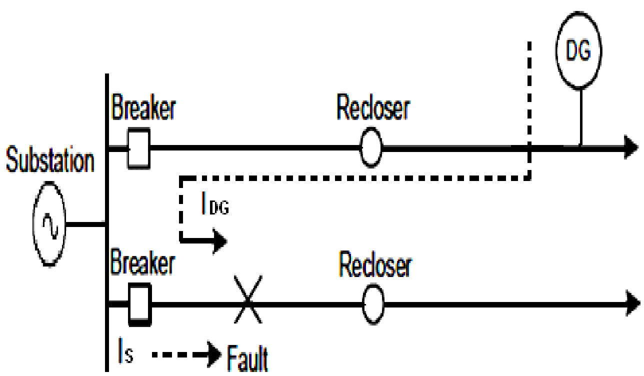

Fig. (4) False Tripping[3]

As a reinforcement, the false tripping on healthy feeders may probably solved by using directional overcurrent relay for the circuit breaker [5], [8]. One of the solutions regarding the fuse blowing is limiting the contribution of DG, instead of replacement or new settings [9], [10]. This method is possible and does not require a great investment. The principle is that there is a margin of the fault current from DG sources for the loss of protection coordination.

IV. Determining The Margin Of Fault Current

Since the false tripping seems easier to be handled, only the fuse blowing will be concentrated in this section. The proposed method is based on the protection coordination constraints to find the size margin of DG source. In addition, this section proposes another set of equations subject to operating ranges of protective devices.

Fig.(5) shows the system used here for the derivation of margin equations. From Fig.(5), assuming that only one DG is connected in the system, there are four cases as shown in Table (I).

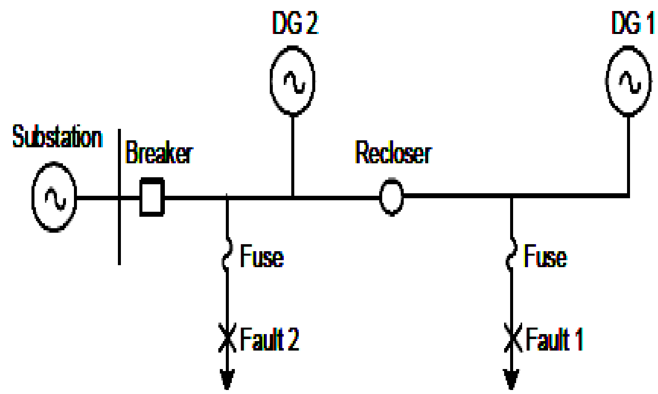

Fig. (5) Sample typical distribution system[3]

TABLE I.
Description of Fault Current Seen by ACR and Fuse

Case	DG source	Fault position	Description
1	DG 1	Fault 1	$I_R = I_S$ and $I_F = I_S+I_{DG}$
2	DG 1	Fault 2	$I_R= I_{DG}$ and $I_F = I_S+I_{DG}$
3	DG 2	Fault 1	$I_R = I_F = I_S+I_{DG}$
4	DG 2	Fault 2	No I_R and I_F = IS+IDG

As shown in Table (I), there is a difference between current flowing through the fuse and the ACR because of contributing the DG in feeding the fault location. Naturally, the disparity between these currents will depend on the size of DG and its placement on the main feeder. Fig.6 illustrates the currents flowing through ACR and fuse in the typical distribution feeder mentioned in Fig.(5). If the difference between I_R and I_F exceeds the margin, for a certain fault current, fuse will be blown before the first closure attempt of the ACR and as a result the coordination will be lost. In compliance the coordination philosophy, considering ACR and fuse operation at the same time, I_{FM} can be achieved by vector summation of DG and distribution substation currents. This value must not be more than the mentioned criteria [3]. In other word:

$$I_S+I_{DG} < I_{FM} \quad (1)$$

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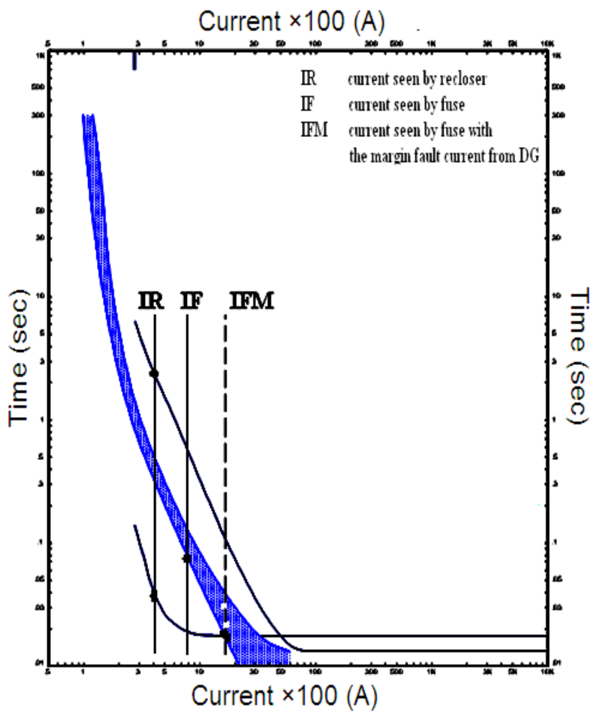

Fig. (6) Coordination margin after penetration of DG

V. PROBLEM FORMULATE

The objective of this study is to recognize the maximum allowable capacity of a DG which does not increase losses in feeder, or cause protection coordination failure. The problem is formulated as a minimization problem to obtain the maximum allowable capacity of a DG to be connected to a feeder.

This section will begin with the defined objective function. Then, sets of constraints, i.e. power loss, and protection coordination, are defined and developed. The calculation procedure is then proposed.

I. Assumption

The DG in this paper is assumed to be a synchronous type. For fault calculation, the total sub-transient reactance including step-up transformer of the DG is assumed to be 0.25 per unit based on a typical value [11], [12]. It is also assumed that the DG capacity is limited to 10 MW, which is applied as the upper limit for the search range of the solution [13]. For simplicity, only three-phase faults are considered in this paper. The number of DG in this study is limited to one DG per feeder. In addition, the possible connection point of the DG is restricted to only on the primary feeder.

II. Objective Function and Constraints

The objective is to determine the maximum allowable capacity of a DG, which can be written as

$$\text{MAX } P_{DG} = \text{MIN } P_{DG} \qquad (2)$$

The constraints are classified into two categories, i.e. feeder loss, and protection coordination. The constraint equations can be presented below.

i. Loss Constraint

The DG capacity allowed to be connected to the feeder will not increase loss of the feeder. The condition can be defined as

$$P_{L1} \leq P_{L2} \qquad (3)$$

ii. Protection Coordination Constraint

Protection constraints are developed to cope with the coordination failure based on the investigation described in Section IV.

Case.1: The coordination failure may occur if the lateral fuse perceives more fault current than the recloser does. In general the fuse saving scheme will be fail if the fault current is higher than a certain value. Therefore, the condition for not losing coordination of the fuse saving scheme is to have the recloser fast curve operating time less than the minimum melting time of the fuse. This constraint is applied when the DG and fault location is as shown in Fig.(5), can be written as

$$T_{Rf}(I_S) \leq MMT_F(I_S+I_{DG}) \qquad (4)$$

Case.2: The problem occurs due to the DG's fault current passing through recloser in the back flow direction. If the DG's fault current is sufficiently high due to its capacity and the recloser is a non-directional type, the recloser may operate with its fast curve before the fuse can clear the fault. This will cause unnecessary momentary interruption to all customers in the feeder behind the recloser. Therefore, fault contribution from the DG should not cause recloser to operate in the case of back flow direction. The constraint can be written as

$$I_R \leq I_{R\ pickup} \qquad (5)$$

$I_{R,Pickup}$ = Pick up setting current of recloser

Case.3: The recloser and fuse will perceive the same fault current. Therefore, to keep the fuse saving scheme coordinated, the constraint below is required.

$$T_{Rf}(I_S+I_{DG}) \leq MMT_F(I_S+I_{DG}) \qquad (6)$$

Case.4: No fault current flows through recloser then the concern is about the fuse interruption rating. Since the DG can lead to higher fault current levels, interrupting current should be taken into account, in this paper, the fuse interrupting capacity is chosen to be 10 kA.

$$I_F \leq 10 \text{ kA} \quad (7)$$

Note that equation (7) is also a constraint for all cases described in this paper.

Based on all the above analysis, the protection constraints to maintain the protection coordination can be summarized in Table II.

TABLE II.
SUMMARY OF PROTECTION CONSTRAINTS

Case	DG position	Fault location	Fault current
A.1	Behind recloser	Behind recloser	(4)
A.2	Behind recloser	In front of recloser	(5)
B.1	Behind recloser	Behind recloser	(6)
B.2	Behind recloser	In front of recloser	(7)

VI. DETERMINATION OF MAXIMUM ALLOWABLE CAPACITY

This section presents a proposed procedure to identify the maximum allowable capacity of the DG at each location along the distribution feeder subjected to the above mentioned constraints. The procedure is illustrated by fig. (7), and can be described below.

1) Run a based case power flow of the existing system and store the results.

2) Select DG connected at bus i and a defined fault location at bus j, then select a proper protection constraint according to Table (II).

3) Apply a direct search method to the objective function in (2) and constraints defined from step 2) to search for maximum allowable DG capacity at bus i with respect to a fault at bus j. Store the result.

4) Repeat step 3) by fixing the DG connected to bus i and change a defined fault location at bus j to every bus in the system.

5) Based on the obtained results from steps 3) – 4), select the minimum value as the solution for the maximum allowable DG capacity connected at bus i.

6) Repeat steps 2) – 5) for all possible DG locations

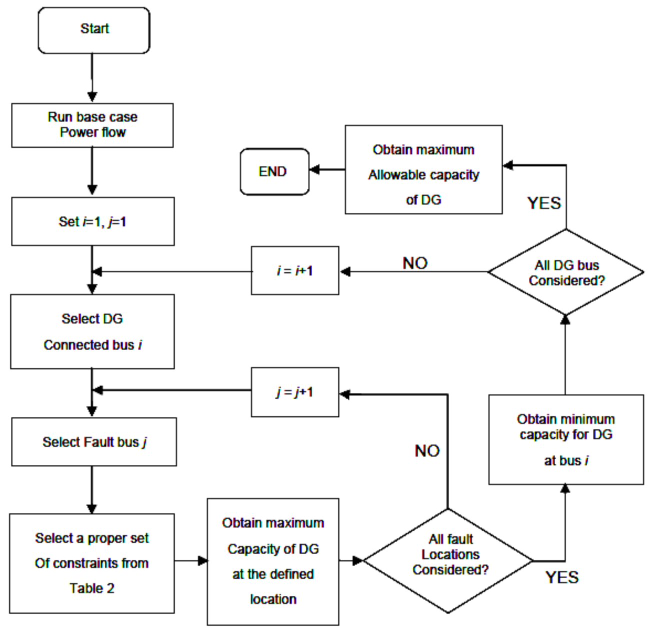

Fig.(7): Procedure for determining maximum allowable capacity of DG

VII. SYSTEM STUDY

This section describes about the distribution network used as the test system in this paper. Details of protection settings are also provided.

i. Case Study

A modified RBTS BUS 2[14] shown in Fig.(7) is used as the test system in this paper. A 200 MVA fault level is assumed at the station bus. In this test system, the line length is assumed to be increased by five times of the original data whereas the operating voltage is modified from 11 to 22 kV to be comparable with a typical characteristic of a distribution feeder of the Provincial Electricity Authority of Thailand.

In Fig.(7), LP is represented for load point, and "R" is for a mid-line recloser. The number followed by capitalized letter indicates possible DG locations on each feeder. As an example, (3A) represents the possible DG location is at point A in Feeder 3. All necessary parameters, e.g. impedance, line length, and load are shown in Tables III to VI. It was found from the base case analysis that the total system loss with no presence of DG is of 636 KW.

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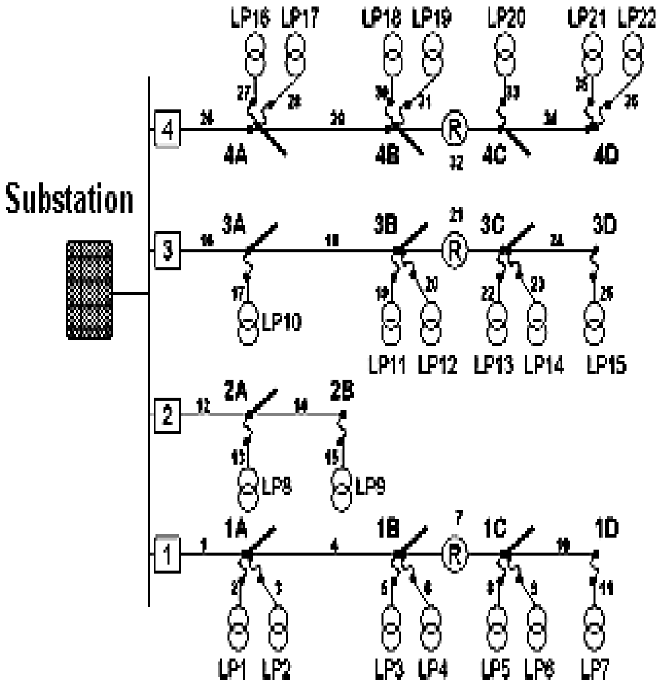

Fig.(7) Test System[14]

TABLE III.
FEEDER DATA[14]

Main Feeder	0.211 + 0.414j ohm/Km
Lateral Feeder	0.341 + 0.456j ohm/Km

TABLE IV.
FEEDER IMPEDANCE (OHM/KM)[14]

Feeder no.	Feeder length (Km)
2, 6, 10, 14, 17, 21, 25, 28, 30, 34	3
1, 4, 7, 9, 12, 16, 19, 22, 24, 27, 29, 32, 35	3.75
3, 5, 8, 11, 13, 15, 18, 20, 23, 26, 31, 33, 36	4

TABLE V.
LOAD INFORMATION[14]

load point (LP)	Customer Type	Real Power (MW)	Reactive Power (MVAR)
1,2,3,10,11	Residential	0.8668	0.6934
12,17,19	Residential	0.7291	0.5833
8	Medium Industry	1.6279	1.3023
9	Medium Industry	1.8721	1.4977
4, 5, 13, 14, 20, 21	State agency	0.9167	0.7334
6, 7, 12,15, 16, 22	Commercial	0.75	0.6

ii) Protection Coordination

There are two key types of protective devices used in the test system, i.e. recloser and fuse. It is assumed that relays and circuit breakers are installed at the beginning of each feeder and well-coordinated with other protective devices. A non-directional type recloser with application of fuse saving scheme, is placed at the middle of each feeder except for Feeder 2. Fuse link is assumed to be of type K, i.e. fast type.

Protection coordination is set according to a general practice [15], [16]. For simplicity, only the three-phase faults are considered in this paper. The phase setting and operating curve of the protective devices can be summarized in Table VI. An example of time-over current coordination between recloser and fuse type K50A is presented in Figure 8

TABLE VI.
PROTECTIVE DEVICE SETTINGS

Feeder	Circuit Breaker	Recloser	Fuse Type K (Branch)		
			40A	50A	65A
1	Curve=SI Ip=411A, Dial=0.1	F_curve=101 S_curve=116 Ip=260A	2 3 5 6	8 9 11	-
2	Curve=SI Ip=300A, Dial=0.2	None	-	-	13 15
3	Curve=SI Ip=349A, Dial=0.15	F_curve=101 S_curve=116 Ip=260A	17 19 20	22 23 25	-
4	Curve=SI Ip=383A Dial=0.1	F_curve=101 S_curve=116 Ip=260A	27 28 30 31	33 35 36	-

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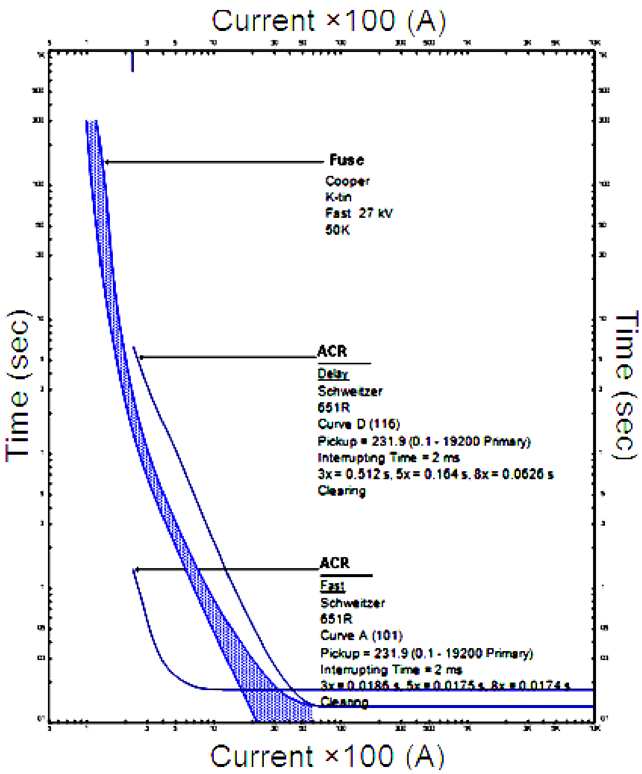

Fig. (8) Time coordination curve of protective device in feeder

VIII. Results

This section presents all the results obtained from the proposed method. The analysis is divided into 3 cases according to constraint considerations, i.e

1) Protection coordination constraint,

2) Line loss constraint, and

3) Maximum allowable capacity and optimal location of the DG.

The results of the maximum allowable capacity of the DG at each location of the test system are shown in Table VII. In addition, the percentage of the line loss reduction compared to the base case with no DG is also included

TABLE VII.
Simulation Results

Feeder	DG location	Fault location/ Recloser	Maximum allowable DG size capacity (MW) / Loss reduction (%)		
			Case 1	Case 2	Case 3
1	1A	In front	6.0416 / 17.29%	6.0416 / 17.29%	2.9 / 23.58% at 1C
		Behind	2.90 / 14.15%	6.0416 / 17.29%	
	1B	In front	5.1002 / 24.75%	5.1002 / 24.75%	
		Behind	2.90 / 21.54%	5.1002 / 24.75%	
	1C	In front	4.2065 / 25.28%	4.2065 / 25.28%	
		Behind	2.90 / 23.58%	4.2065 / 25.28%	
	1D	In front	3.5199 / 22.16%	3.5199 / 22.16%	
		Behind	2.90 / 21.69%	3.5199 / 22.16%	
2	2A	In front	3.5362 / 5.66%	3.5362 / 5.66%	2.7703 / 6.44% at 2B
	2B	In front	2.7703 / 6.44%	2.7703 / 6.44%	
3	3A	In front	5.1318 / 12.59%	5.1318 / 12.59%	1 / 13.36% at 3C
		Behind	1 / 7.07%	5.1318 / 12.59%	
	3B	In front	4.6329/ 20.97%	4.6329/ 20.97%	
		Behind	1 / 11.94%	4.6329/ 20.97%	
	3C	In front	4.0683 / 22.30%	4.0683 / 22.30%	
		Behind	1 / 13.36%	4.0683 / 22.30%	
	3D	In front	3.2215 / 19%	3.2215 / 19%	
		Behind	1 / 12.57%	3.2215 / 19%	
4	4A	In front	5.6005 / 16.13%	5.6005 / 16.13%	4.1075 / 24.76% at 4C
		Behind	4.76 / 15.88%	5.6005 / 16.13%	
	4B	In front	4.8503 / 23.22%	4.8503 / 23.22%	
		Behind	4.76 / 23.27%	4.8503 / 23.22%	
	4C	In front	4.1075 / 24.76%	4.1075 / 24.76%	
		Behind	4.76 / 24.37%	4.1075 / 24.76%	
	4D	In front	3.6055 / 24.10%	3.6055 / 24.10%	
		Behind	4.76 / 22.48%	3.6055 / 24.10%	

From the results in Table VII, protection coordination clearly has impact in determining the maximum allowable capacity. If the protection coordination is ignored, i.e. only system voltage and line loss are considered, the results of the maximum allowable DG capacity will become larger. For example, considering Feeder 1 without protection coordination constraint as of Case 2, the maximum allowable capacity of a DG at node 1A is 6.0416 MW, which may, however, cause protection coordination failure. In Case 3, if the protection coordination is taken into account, the maximum allowable capacity of a DG at node 1A reduces to 2.9 MW.

It is clearly shown that the developed method is a tool for distribution system engineers. A utility officer can quickly calculate the capability of allowing a DG connected to the existing system. This will help the utility officer screen the applied DG projects. If the DG is of less capacity, the utility officer will know that such a DG will not cause problem to the existing network in terms of loss, voltage profile, and protection coordination. Nonetheless, a larger capacity of the DG implies that the existing system needs to be modified or upgraded.

IX. CONCLUSION

This paper proposes a methodology to determine the maximum allowable capacity of a DG and optimal location taking into protection coordination, and loss constraints. In obtaining the results, a direct search method is applied with a proper set of constraints related to the DG and the fault locations. Impacts between loss and protection coordination constraints on the allowable DG capacity were analyzed. The obtained results in this paper show that protection coordination constraint dominates the line loss constraint. If the protection coordination is not considered, the maximum allowable capacity will be larger, but may cause protection coordination failure. The value of SDG must be the smallest among all coordination constraints of recloser and fuses. This means that the most sensitive fuse to be blown should be selected to determine the lowest margin of DG size.

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