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A Protection Coordination Index for Evaluating Distributed Generation Impacts on Protection for Meshed Distribution Systems

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***Abstract*—Depending on the capacity, type and location, distributed generation (DG) can have an impact on protection coordination of directional over-current relays for looped distribution systems. In this paper, a new index is proposed, "protection coordination index" (PCI), which can serve as an effective measure when planning the protection of meshed distribution systems with DG. A two-phase non-linear programming (NLP) optimization problem is proposed to determine the PCI by optimally calculating variations in the maximum DG penetration level with changes in the protection coordination time interval. Furthermore, the influence of connecting a DG at a certain location on the system PCIs is examined. The presented analysis is tested on the distribution section of the IEEE 14-bus and IEEE 30-bus systems. The PCI can serve as an efficient index for distribution system planners: (i) to determine the best DG candidate locations for utility owned DG and (ii) to evaluate the impact of a customer owned DG, considering distribution system protection.**

***Index Terms*—Distributed generation, faults, optimization, protection coordination.**

I. Introduction

CURRENT Distribution systems can accommodate limited number of distributed generation (DG) due to voltage profile and short circuit variations which consequently affect the power quality and protective relaying [1]. The situation becomes more severe with the increase in the DG penetration level [2]. In [3], it is shown that the dynamic behavior and transient stability of a power system can become a concern with increased DG penetration. The amount of DG penetration can be limited by the conductor ampacity, voltage regulation and short circuit currents [4]. In [5], DG impacts were evaluated using a multi-objective index which takes into account real and reactive power losses, voltage, conductor capacity, and short circuit levels. Such indices can be used in identifying where the DG has least impact on the distribution network.

New techniques are needed and essential to determine the maximum amount of DG that could be installed without requiring major changes to the distribution network [6]. In [7], the maximum allowable DG penetration level considering the IEEE 519 standard harmonic limits was studied. Closed form equations were derived for radial distribution systems with uniform, linearly increasing or linearly decreasing load patterns. In [8], the maximum amount of active power that can be supplied by the DG at each bus of a radial distribution system, taking into account voltage violations, was determined using repetitive power flow studies. In addition, an index is proposed to help utility managers in identifying which DGs are responsible for the voltage violation. Analytical expressions for simple radial distribution system were developed, in [6], to determine the allowable DG penetration considering conductor ampacity and voltage rise.

Protection device coordination for distribution systems can be affected, as well, by the integration of DG [1]. Synchronous based DG has a much more profound effect on protection coordination than inverter based DG [9]. In [2], the impacts of inverter based DG on re-closer/fuse coordination were investigated with inverter based DG and a DG interface control was proposed to mitigate such impact. In [10], [11], the maximum allowable DG penetration level for radial distribution systems was calculated considering protection coordination. Due to the radial nature of the system, a simple approach relying on the protective device characteristic can be implemented to determine the allowable penetration level at each bus. In [12], a method that relies on optimally locating fault current limiters to minimize the impacts of DG on protection coordination in radial distribution systems was proposed and solved using particle swarm optimization. Due to the integration of DG and the recent drive towards smart grids, distribution systems are expected to be more of the meshed structure [13]–[15]. In [16], a reliability assessment algorithm is developed considering meshed distribution systems. In [17], a new hybrid structure allowing both radial and meshed operation of the distribution system is proposed to increase DG penetration. Identifying the impact of DG penetration for looped distribution systems on protection coordination problem with directional over-current relays is more complicated and has not been addressed in previous literature.

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In this paper, a protection coordination index is defined and proposed for use in determining the impact of integrating DG (synchronous based type) on the protection of meshed distribution system. A two-phase nonlinear programming optimization problem is proposed for calculating the PCI and is applied to the power distribution network of the IEEE 14-bus and IEEE 30-bus system. The PCI is calculated by optimally determining the rate of change of the DG penetration level with respect to the change in coordination time interval. The usefulness of the proposed PCI for distribution system planners in evaluating the impacts of both utility owned and customer owned DG is discussed and analyzed.

II. Proposed Approach to Determine the Protection Coordination Index

Due to the bi-directional fault current flow, directional over-current relays (OCR) are used for protecting looped distribution systems. The operation time (t) of a directional OCR is an inverse function of the short-circuit current flowing through it. This function is defined by two parameters, namely the time-dial settings (TDS) of the relay and the pickup current (I_p), which is the minimum value of current above which the relay will start to operate. The relay time-current characteristic can be expressed as follows:

$$t_{ij} = TDS_i \frac{A}{\left(\frac{I_{scij}}{I_{pi}}\right)^B - 1} \tag{1}$$

where i is the relay identifier and j is the fault location identifier. A and B are constants that vary with the type of OCR which are set to 0.14 and 0.02, respectively. The term I_{scij} represents the relay short circuit current and I_{pi} represents the relay pickup current.

The protection coordination index, PCI, is defined as the rate of change of the maximum DG penetration level with respect to the rate of change of coordination time interval CTI. To determine the PCI, a two-phase protection coordination optimization model is proposed for looped distribution systems with directional over-current relays. In Phase I, the settings of the relays are determined using the conventional protection coordination (CPC) optimization model and with no DG present in the system [18]. Various methods have been proposed to optimally solve the CPC model which includes the DICOPT solver in GAMS [19], genetic algorithms [20], evolutionary algorithm [21], MATLAB optimization toolbox [22] and particle swarm optimization [23]. The outputs of phase I are the optimal relay settings which include the time-dial and the pickup current settings. These settings are inputted to Phase II as parameters where the main objective is to determine the maximum allowable DG penetration level considering protection coordination and relay operating time constraints. The DG penetration level is optimally calculated considering various CTI values to determine the PCI at each DG candidate location. Fig. 1 presents a block diagram of the proposed two-phase formulation. As can be seen, the output of Phase I, which includes the optimal relay settings, is an input to Phase II where the main objective is to maximize the DG penetration. In comparison to a conventional protection coordination study, the proposed approach involves an additional algorithm (Phase II) to calculate the PCI.

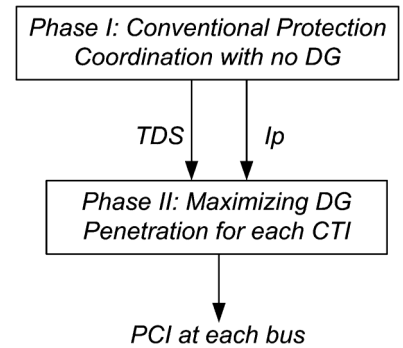

Fig. 1. Proposed two-phase problem formulation.

A. Phase I: Conventional Protection Coordination Formulation

The settings of the relay are commonly calculated by formulating an optimization model where the main objective is to minimize the sum of relay operating time (T) subject to protection coordination, relay setting and relay operating time constraints. The main optimization variables are the relay settings which include the TDS and I_p as well as the total relay operating time. This model will be denoted as the CPC formulation and can be expressed as follows:

$$Minimize \quad T = \sum_{i=1}^{N} \sum_{j=1}^{M} \left(t_{ij}^p + t_{ij}^b\right) \tag{2}$$

where N is the total number of relays and M is the total number of fault locations investigated. Variables t_{ij}^p and t_{ij}^b represent the primary relay i operating time and the backup relay i operating time for a fault at location j, respectively. The CPC formulation includes protection coordination constraints such that in case a primary relay fails to isolate the fault in its zone, a backup relay will operate. To assure proper coordination, a minimum gap in time between the operation of primary (t_{ij}^p) and backup relays (t_{ij}^b), known as the CTI, needs to be maintained. The protection coordination constraint can be expressed as follows:

$$t_{ij}^b - t_{ij}^p \geq CTI. \tag{3}$$

In addition to the above, there are upper and lower bound constraints on the relay settings and relay operating time which can be expressed as follows:

$$I_{pi-\min} \leq I_{pi} \leq I_{pi-\max}, \forall i \tag{4}$$

$$TDS_{i-\min} \leq TDS_i \leq TDS_{i-\max}, \forall i \tag{5}$$

$$0 \leq t_{ij}^p, t_{ij}^b \leq t_{ij-\max}, \forall i, j \tag{6}$$

where I_{pi-min} and I_{pi-max} are the lower and upper limits on the relay pickup current setting and TDS_{i-min} and TDS_{i-max} are the lower and upper limits on the relay TDS setting which are set to 0.1 and 11, respectively. Parameter t_{ij-max} represents the maximum relay operating time which will depend on the utility

operator design criterion. For numerical relays, I_p can be set as a continuous variable.

B. Phase II: DG Maximization Formulation

In Phase II, the relay settings (TDS and I_p) are treated as fixed parameters with values calculated from Phase I. The proposed approach calculates the PCI by optimally determining the change in the maximum achievable penetration level with CTI. In Phase II, the main objective is to maximize the DG penetration (P) as follows:

$$Maximize \quad P = \sum_{k=1}^{L} S_{DGk} \tag{7}$$

where S_{DGk} is the DG MVA rating to be installed at bus k and L denotes the number of DG. Similarly, constraints (3) & (6) are included in the problem formulation. One important difference between Phase II and Phase I is the short circuit calculation procedure. In Phase I, since there are no DG units in the distribution system, the short circuit currents are calculated and are inputted as a parameter in (1). On the contrary, for phase II, the short circuit currents vary depending on the DG location and capacity. Inserting DG at certain locations affect the bus admittance matrix which in turn changes the bus impedance matrix resulting in variations in short circuit current values. Thus, the short circuit current in (1) is a function of the DG capacity as follows:

$$I_{scij} = f(S_{DGk}). \tag{8}$$

In addition, an upper limit is set on the DG capacity that can be installed, at each DG bus, as follows,

$$0 \leq S_{DGk} \leq S_{DGk-\max}, \forall k \tag{9}$$

where $S_{DGk-max}$ represents the upper limit on the DG capacity to be installed at each location which is set to 10 MVA. The value of $S_{DGk-max}$ will depend on the utility planner design preference. The DG penetration level P in (7) is calculated for different values of CTI and the rate of change of P $(\Delta \mathrm{P})$ with respect to the rate of change of CTI $(\Delta \mathrm{CTI})$ is calculated to determine the PCI. Thus, the PCI index can be defined as follows:

$$PCI = -\frac{\Delta P}{\Delta CTI.} \tag{10}$$

The units of PCI are in MVA/s. The PCI is defined such that a positive value indicates that a reduction in CTI will result in an increase in the DG penetration. Higher values for PCI at certain locations indicate that higher DG penetration levels can be achieved with less impact on protection coordination (or in other words with small changes in CTI).

III. System and Simulation Setup

The proposed two-phase problem formulation is applied to the distribution network of the IEEE 14-bus and the IEEE 30-bus power systems. For brevity, the paper will focus on analyzing in details the results of the IEEE 30-bus system whereas some of the analysis and simulation results for the IEEE 14-bus system will be provided. In this section, a description of the case studies analyzed, for which the PCI is calculated, is presented. Furthermore, a flowchart detailing the various components of the proposed algorithm is presented and explained.

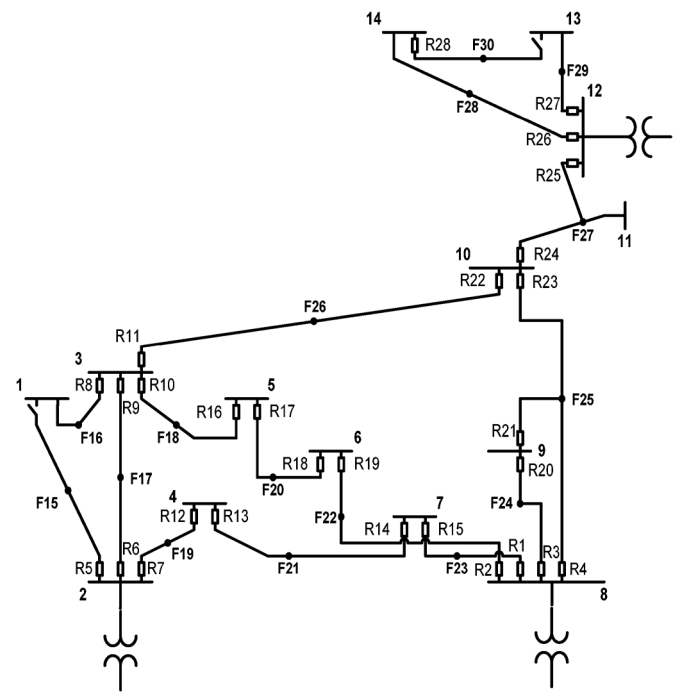

Fig. 2. Power distribution system of the IEEE 30-bus system under study.

A. Test System Under Study

The single-line diagram of the power distribution system of the IEEE 30-bus test system, where power is fed from more than one point, is depicted in Fig. 2. The power distribution system of the IEEE 14- bus system is given in Appendix I. Detailed system parameters can be found in [24]. The distribution system is fed through three 50 MVA 132 kV/33 kV transformers connected at buses 2, 8 and 12. Ten buses have been selected as candidate locations for DG installation and these buses include 2 to 10 and bus 12. All DG units are connected to the system through a 480 V/33 kV step-up transformer with 0.05 p.u transient reactance. The system is equipped with 28 directional over-current relays. Similarly, the short circuit currents are calculated by conducting a bolted three-phase midway fault on each line. The fault locations are denoted as F15 to F30 as shown in Fig. 2. For both systems, the chosen DG technology is a synchronous type with 0.0967 p.u transient reactance based on its capacity. It is assumed that all relays are identical and have the standard inverse relay curves with the following parameters 0.14 and 0.02 for A and B, respectively.

As stated in [25], DG can be either owned by the utility or by a customer and in both cases there could be an impact on protection coordination. For utility owned DG, the PCI can be used in identifying the best location on the distribution system which would result in minimum impact on protection coordination. For customer owned DG, there is no control over the location of the DG as it depends mainly on the customer location. In such case,

the PCI can be used as a measure for utility operators to determine if changes and modifications are needed for the protection system as a result of a customer owned DG interconnection. In this paper, the applicability of the PCI in planning the distribution system protection considering both utility and customer owned DG is examined. In addition, the sensitivity of the PCI value at a specific location as a result of changes in location and size of DG at other locations is investigated.

B. Algorithm Implementation

The two-phase protection coordination optimization problem, presented in Section II, is implemented in MATLAB and solved using the *fmincon* function which uses the reduced gradient approach (first order optimality) for solving constrained non-linear optimization problems. In Phase I, the relay settings are optimally determined for the system considering no interconnected DG. The main algorithm steps for Phase I are as follows.

1) Construct the system impedance matrix $(\mathrm{Z_{bus}})$ with no DG.
2) Calculate the midway three phase short circuit currents passing through all relays in both primary and backup modes.
3) Perform Phase I of the optimization model and obtain optimal TDS and I_p values.

The output of Phase I (TDS and I_p) is inputted to Phase II as parameters. For Phase I, the system impedance matrix, as well as the short circuit currents, is independent of the optimization variables (TDS and I_p). For Phase II, since the objective is to calculate the PCI by determining the rate of change of DG capacity at selected candidate locations, both the system impedance matrix and short circuit currents will vary with variations in DG capacity and location. The main steps for Phase II are as follows.

1) Set initial values for CTI and select the DG location.
2) Construct the system impedance matrix which will be a function of S_{DGk}.Calculate the three phase short circuit currents passing through all relays in both primary and backup modes.
3) Perform Phase II of the optimization model and obtain S_{DGk} at the selected bus location.
4) Change the CTI values and repeat steps 2 to 5.
5) Calculate the PCI at the selected bus location k.

Fig. 3 presents a flowchart of the proposed two-phase optimization problem.

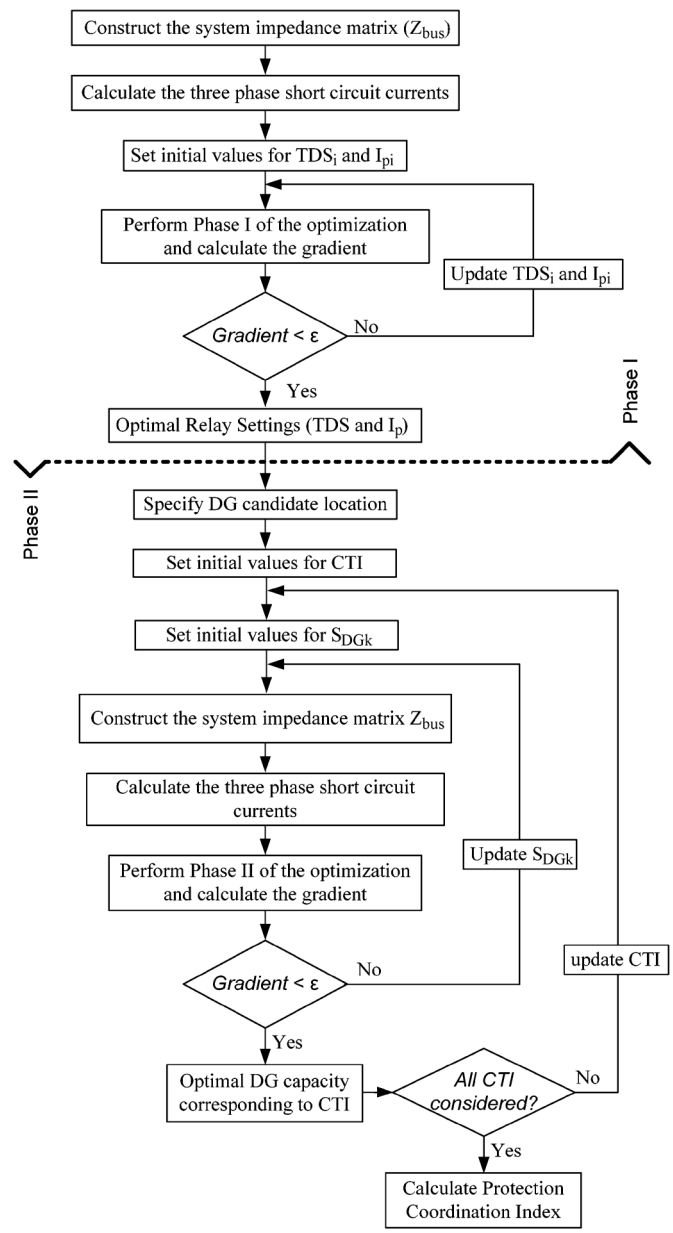

Fig. 3. Proposed two-phase problem formulation.

IV. Protection Coordination Index Analysis

The conventional protection coordination (Phase I of the proposed algorithm) is applied to the power distribution system of the IEEE 30-bus system to minimize the total operating time T as in (2) by choosing the optimal relay settings and operating time. Table I presents the optimal relay settings for the IEEE 30-bus case considering no DG interconnection. The relay operating times (primary and backup) are given in Table II. Table II also presents the backup and primary relay pairs for faults F15 to F30.

Depending on the fault location, there can exist more than one backup for a relay. The results were obtained for $CTI = 0.3$ s and a maximum relay operating time of 2.5 s. The TDS setting, for the majority of relays, hits the lower bound which is 0.1 s. In addition, it can also be seen from Table II that the coordination constraint presented in (3) is binding for the majority of fault locations. For example, for a fault at F19, the difference between the backup relay (R9) and primary relay (R7) is 0.3 seconds which is equal to the CTI limit. The results presented in Table I will be inputted to Phase II of the optimization problem to determine the proposed PCI.

Similarly, the conventional protection coordination algorithm is applied on power distribution system of the IEEE the 14-bus system to minimize the total operating time T as in (2) by choosing optimal relay settings. The optimal relay settings for the IEEE 14-bus case considering no DG interconnection is given in Appendix II.

TABLE I
OPTIMAL RELAY TDS AND IP SETTINGS FOR IEEE 30-BUS CASE

Relay	*TDS(s)*	*Ip(p.u)*	*Relay*	*TDS(s)*	*Ip(p.u)*
1	0.1	0.832	15	0.3102	0.0684
2	0.1	0.6481	16	0.2383	0.0605
3	0.1	0.9675	17	0.1	0.3713
4	0.1	0.1373	18	0.1	0.4379
5	0.1	0.0767	19	0.1	0.1828
6	0.1	0.6696	20	0.2853	0.0789
7	0.1	0.699	21	0.5786	0.0166
8	0.1	0.0196	22	0.1793	0.1252
9	0.1	0.2485	23	0.4036	0.0627
10	0.1	0.583	24	0.1	0.1569
11	0.1	0.1938	25	0.267	0.1788
12	0.1	0.2497	26	0.1	0.2166
13	0.1	0.5174	27	0.1	0.0622
14	0.1	0.4763	28	0.1	0.0367

TABLE II
OPTIMAL PRIMARY AND BACKUP RELAY OPERATING TIMES

Fault Location	Operating times of relays in sec. (p = primary, b = backup) p	b_1	b_2	b_3	b_4
F15	*R5*	*R9*	*R12*	-	-
	0.1889	0.7381	0.8579	-	-
F16	*R8*	*R6*	*R16*	*R22*	-
	0.1380	0.9136	0.7892	0.8365	-
F17	*R6*	*R12*	-	-	-
	0.5035	0.8035	-	-	-
	R9	*R16*	*R22*	-	-
	0.4233	0.7233	0.7233	-	-
F18	*R10*	*R6*	*R22*	-	-
	0.5497	0.8497	0.8497	-	-
	R16	*R18*	-	-	-
	0.5871	0.8871	-	-	-
F19	*R7*	*R9*	-	-	-
	0.5591	0.8591	-	-	-
	R12	*R14*	-	-	-
	0.4328	0.7328	-	-	-
F20	*R17*	*R10*	-	-	-
	0.5415	0.8415	-	-	-
	R18	*R2*	-	-	-
	0.5902	0.8902	-	-	-
F21	*R13*	*R7*	-	-	-
	0.6920	0.9920	-	-	-
	R14	*R1*	-	-	-
	0.4746	0.7746	-	-	-
F22	*R2*	*R15*	*R20*	*R21*	*R23*
	0.6235	1.6245	2.1938	1.6035	1.7005
	R19	R17	-	-	-
	0.4078	0.7078	-	-	-
F23	*R1*	*R19*	*R20*	*R21*	*R23*
	0.5111	1.0592	1.1351	1.1906	1.1198
	R15	*R13*	-	-	-
	0.7953	1.0953	-	-	-
F24	*R3*	*R15*	*R19*	*R21*	*R23*
	0.6049	0.9049	0.9049	0.9049	1.0132
	R20	*R4*	*R23*	-	-
	0.7132	1.0132	1.1198	-	-
F25	*R4*	*R15*	*R19*	*R20*	-
	0.3193	0.9637	1.2656	0.6193	-
	R21	*R3*	*R25*	-	-
	0.8243	1.1243	1.2548	-	-
	R23	*R11*	-	-	-
	0.9548	1.2548	-	-	-
F26	*R11*	*R6*	*R16*	-	-
	0.3256	1.0916	0.9777	-	-
	R22	*R4*	*R21*	*R25*	-
	0.5230	1.0142	1.2151	1.4906	-
F27	*R24*	*R4*	*R11*	*R21*	-
	0.3246	0.7751	0.8335	1.1386	-
	R25	-	-	-	-
	0.8328	-	-	-	-
F28	*R26*	*R24*	-	-	-
	0.3425	0.6425	-	-	-
F29	*R27*	*R24*	-	-	-
	0.1968	0.5475	-	-	-
F30	*R28*	*R26*	-	-	-
	0.2182	0.5182	-	-	-

A. Application of PCI to Meshed Distribution Networks

The DG maximization problem, presented in Section II-B, is solved using the optimal relay settings presented in Table I. The CTI is varied and for each value of CTI, the maximum DG penetration level at each possible candidate DG location is optimally determined. It is worthy to note that the choice of CTI depends on the protection system designer and can range from 0.2 to 0.3 s. Fig. 4 presents the maximum percentage DG penetration level obtained by the reduced gradient approach at selected buses versus the CTI values. The percentage DG penetration was calculated by determining the ratio of DG penetration in MVA with respect to the total system MVA (150 MVA for the IEEE 30 bus system and 120 MVA for the IEEE 14 bus system). As defined earlier, the PCI is the rate of change of the maximum DG penetration level with respect to CTI. The average slope of the curve presented in Fig. 4 is calculated and Table III presents the PCI values obtained. Locations with higher PCI result in lower DG impact on protection coordination.

The *DG penetration versus CTI* curves, presented in Fig. 4, can be used in indentifying the best location to install a utility owned DG. For example, if the utility wants to install a 5 MVA DG and assuming that the possible candidate locations are busses 2, 3, 6, 9, 10, and 12, then the best location to install the DG would be bus 12. As seen from the curves, installing a 5 MVA DG at location 12 will result in the least change in CTI ($\sim$0.275 s). For such case, the utility might not need to modify the relay settings since the impact is minimal. On the contrary, if the possible candidate DG locations are 5 and 6 only, bus 5 would be the best option since it has a higher PCI. But, by referring to Fig. 4, a 5 MVA DG at bus 5 would result in a significant impact on protection coordination ($\mathrm{CTI} \ll 0.22s$) and in such case, the relay settings must be modified to accommodate the DG.

For customer owned DG, utility operators have no control over the location and size of the DG to be installed. It is primarily dictated by the customer preference and location. The *DG penetration versus CTI* curves as well as the PCI can provide utility operators with a fast and accurate assessment of the impact of a customer owned DG. For example, for a customer requesting to install 0.5 MVA DG at bus 9, the CTI will change by 0.5/89.69 which will result in a CTI of 0.294 seconds. Installing the same DG capacity at bus 6 will change the CTI by 0.5/12.3175 resulting in an overall CTI of 0.259. The PCI can thus help utility planners and designers to assess impact of DG integration as well as identify the best candidate locations for DG that would have least impact on protection coordination.

The same analysis is applied to the distribution system of the IEEE 14-bus system. The *DG penetration versus CTI* curves are

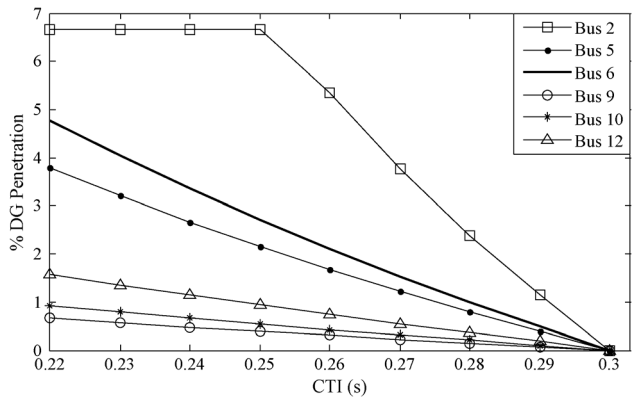

Fig. 4. Variation of DG penetration with CTI for the IEEE 30 bus system.

TABLE III
PCI FOR THE IEEE 30 BUS CASE

DG Bus	*PCI*	*DG Bus*	*PCI*
2	29.3738	7	35.4363
3	15.5813	8	27.6650
4	24.1713	9	89.6900
5	17.4538	10	70.9363
6	12.3175	12	200.0000

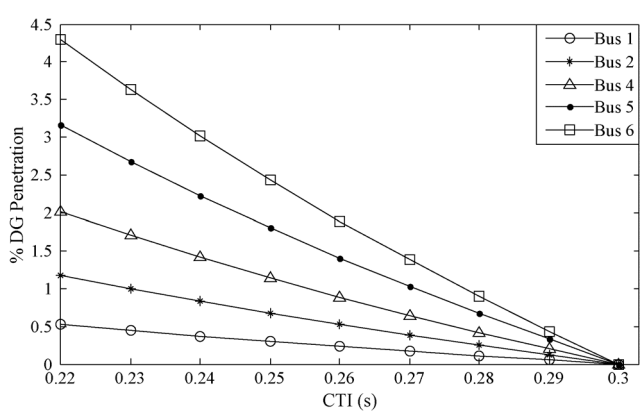

Fig. 5. Variation of DG penetration with CTI for the IEEE 14 bus system.

TABLE IV
PCI FOR THE IEEE 14 BUS WITH 7 DG CANDIDATE LOCATIONS

DG Bus	*PCI*	*DG Bus*	*PCI*
1	64.3638	5	17.5675
2	47.4450	6	7.7850
3	17.8175	7	13.2975
4	30.2700		

given in Fig. 5. Table IV presents the PCI at the various buses on the system. From the results, it can be observed that bus 1 has the maximum PCI and thus a DG installed at that location will have least impact on protection coordination. On the contrary, bus 6 has the least PCI value which indicates that adding a DG at such location will have greater impact on protection coordination.

B. Impact on PCI due to Installed DG

Since the fault current magnitudes will vary with the integration of DG, it is expected that the PCI will also vary. In this section, the effect that an installed DG at a specific location might have on the PCI at other locations is examined. In order to analyze the interaction between DG units installed in the system and its effect on PCI, pre-installed DG of fixed rating is considered to be connected already in the system. In the IEEE 30-bus test system, a pre-installed DG of 5 MVA rating is connected at bus 10. The *DG Penetration versus CTI* curves at two selected buses 2 and 5 are shown in Fig. 6. It can be seen that the impact on the protection coordination could be positive or negative. The PCI at bus 2 would decrease when a customer, at bus 10, installs a 5 MVA DG. The PCI at bus 2 has decreased from 29.3738 (with no DG at bus 10) to 26.8263 (with a 5 MVA DG). On the contrary, for bus 5, the PCI increased from 17.4536 to 18.823 when a 5 MVA DG is installed at bus 10.

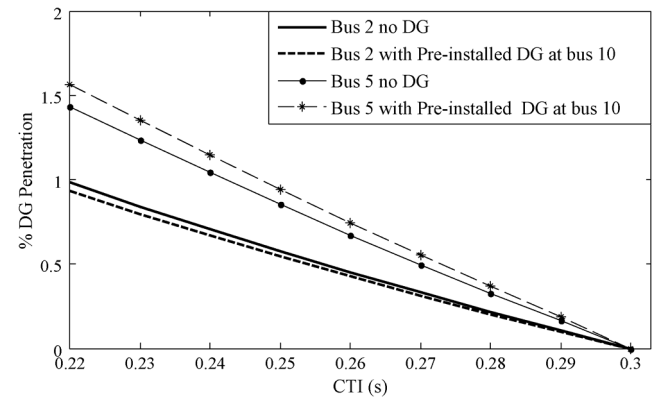

Fig. 6. Variation of DG penetration over CTI with preinstalled DG for the IEEE 30 bus system.

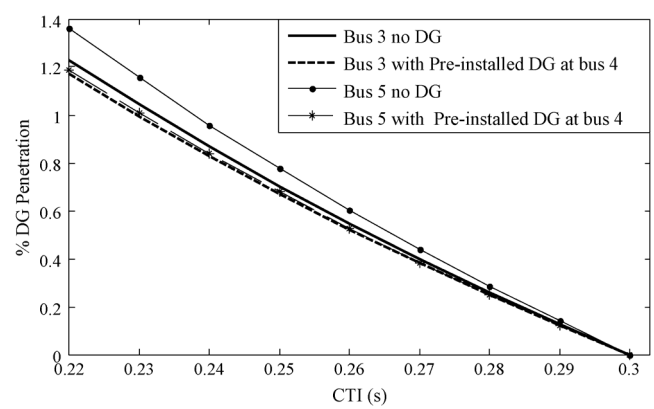

Fig. 7. Variation of DG penetration over CTI with preinstalled DG for the IEEE 14 bus system.

Similarly, in the case of IEEE 14-bus system, a preinstalled DG of 2.5 MVA rating is considered at bus 4. The *DG penetration versus CTI* curves at buses 3 and 5 are shown in Fig. 7. The protection coordination index at bus 3 increased from 17.8174 to 20.4275 and also increased at bus 5, from 17.5670 to 18.4565.

Furthermore, variations in PCI magnitude, at selected locations, as a result of the variation in the capacity of pre-installed DG at bus 10 are shown in Fig. 8. It can be seen that the PCI level is decreasing at bus 2 with the increase in capacity of pre-installed DG connected at bus 10. On the contrary, the PCI level at bus 5 is increasing with the increase in the capacity of pre-installed DG connected at bus 10. The same analysis has

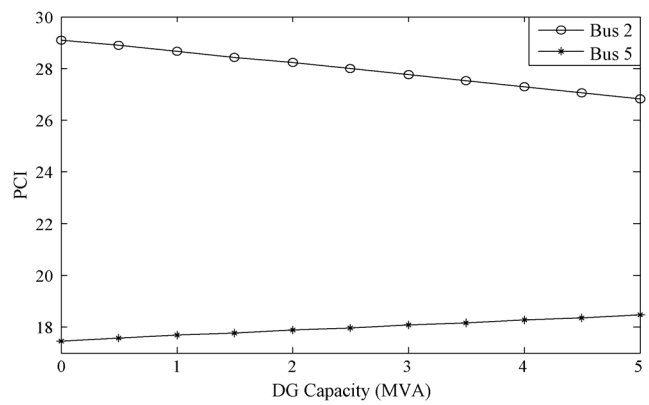

Fig. 8. Variation in PCI values over pre-installed DG capacity for the IEEE 30 bus system.

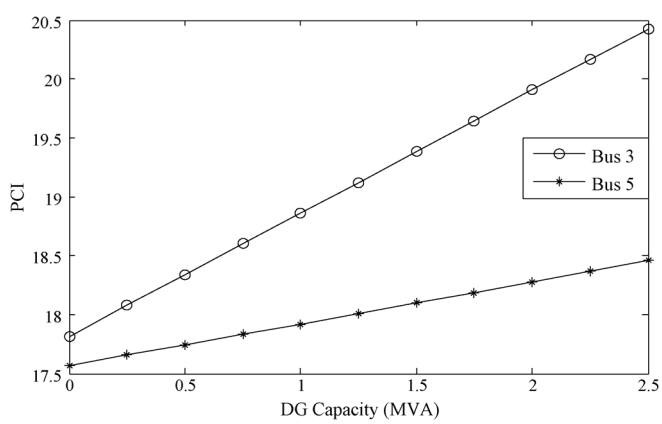

Fig. 9. Variation in PCI over pre-installed DG capacity for the IEEE 14 bus system.

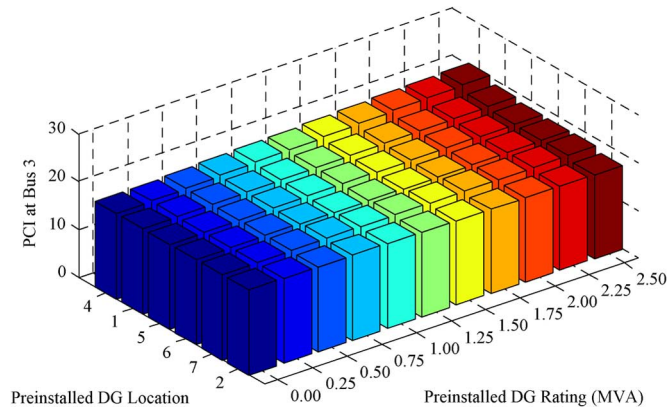

Fig. 10. Impact of pre-installed DG location and capacity on the PCI of bus 3 for the IEEE 14 bus system.

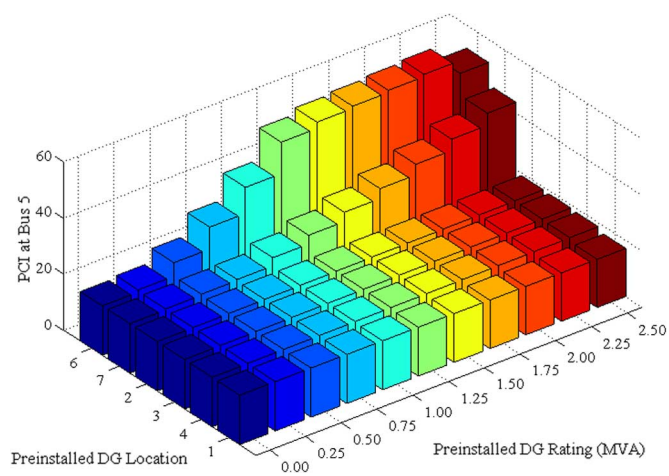

Fig. 11. Impact of pre-installed DG location and capacity on the PCI of bus 5 for the IEEE 14 bus system.

been applied to the power distribution system of the IEEE 14 bus system. It has been noticed that for the case under study, for all buses, there is an increase in the PCI as the DG capacity increases. Fig. 9 presents the variation of the PCI with DG capacity at busses 3 and 5. It can be seen that the PCI level is increasing at bus 3 as well as bus 5 with the increase in the capacity of pre-installed DG connected at bus 4. By referring to Fig. 9 and using (10), with no DG installed at bus 4, a 1 MVA DG installed at bus 3 would result in a drop of 0.056 s in CTI and thus the protection system would be coordinated with a CTI equal to 0.2438 s. With a 2.5 MVA DG installed at bus 4, a 1 MVA DG at bus 3 would drop the CTI to 0.2512 s. This indicates that installing a DG at bus 4 might further allow more DG to be installed at bus 3 with lower impact on the protection coordination.

The results shown in Fig. 8 and 9 indicate that installing a DG at a specific location can either have positive or negative impact on the PCI at other locations on the system. In other words, for cases where the PCI increases (for example, as in the case of Bus 5 in Fig. 8), this indicates that more DG penetration can be achieved with lower impact on protection coordination. On the other hand, a decrease in the PCI at a candidate bus indicates that the impact of installing a DG, on protection coordination, has increased and thus reducing the possible allowable DG penetration to avoid further degradation of the protection coordination.

For this case study, there are two main factors that can impact the PCI value which include the pre-installed DG location and capacity. Figs. 10 and 11 highlight the impact of both the pre-installed DG location and size on the PCI of bus 3 and 5, respectively. For brevity, the results for the IEEE 14 bus system are presented but similar results can be obtained for the IEEE 30 bus system. Each bus PCI varies differently depending on the location and size of the pre-installed DG. In general, the PCI at bus 3 increases in the presence of installed DG at other locations. Bus 3 is most affected by the presence of a DG at bus 4. For bus 5, a pre-installed DG at bus 6 or 7 will have significant impact on the PCI of bus 5. On the contrary, the presence of DG at busses 2, 3, 4 and 1 have minimal effect on the PCI of bus 5. The results also show that the PCI can increase and decrease with the change in pre-installed DG capacity (refer to busses 5 and 6 in Fig. 11).

V. Discussion

In the literature, protection coordination of directional overcurrent relays is commonly analyzed and performed considering

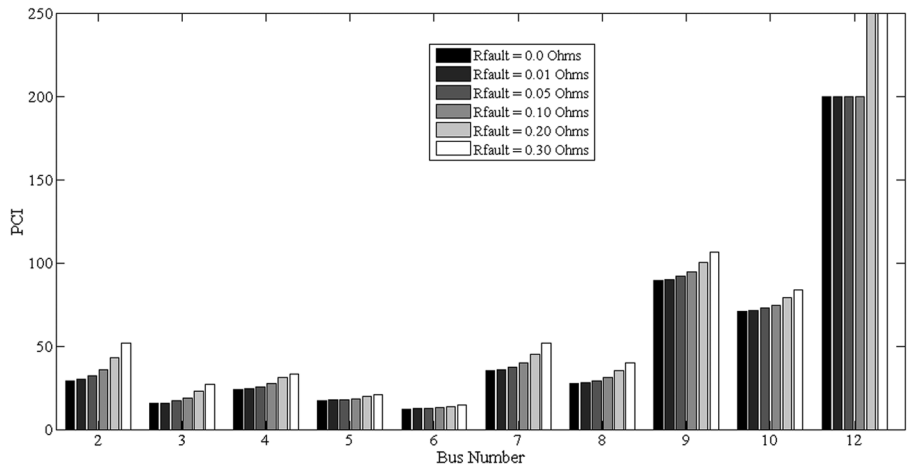

Fig. 12. Impact of fault resistance on PCI value for the IEEE 30 Bus system.

bolted faults [18]–[23]. Thus, the impact of fault impedance is not taken into consideration while determining the optimal relay settings, specifically for directional over-current relays. The fault impedance can range from low values (in the range of milliohms [2], [26]) up to higher values in the range of ohms [2]. In the previous sections, the PCI was determined considering bolted three phase faults. In this section, a preliminary study that discusses the possible impact of faults, with low impedance, on the PCI is presented. Fig. 12 shows the value of PCI at each bus for a three phase fault considering various fault resistance values for the IEEE 30 bus system. First, it can be seen that as the fault resistance increases, the PCI value increases. A higher PCI would indicate that more DG penetration is possible and thus, for the system under study, considering bolted faults would provide a conservative measure for calculating the PCI. Secondly, the fault resistance does not have an impact on the rank of each bus in terms of PCI. In other words, bus 12 remains the optimal location for installing a DG while bus 6 remains the least attractive for installing a DG. For the system under study, higher values of fault resistance will result in protection coordination failure which is expected since the fault current magnitudes will be significantly affected. In [2], for radial systems, it has been shown that the fault impedance has an impact on re-closer/fuse coordination. The impact of higher fault resistance on protection coordination of meshed distribution system and its mitigation is out of the scope of this paper and will be investigated in details in future work.

The impact of a specific DG technology on the PCI will depend primarily on the DG interface. The fault current magnitudes from DG with a synchronous machine interface are much higher than an inverter-based DB unit. Commonly, the interface control of inverter based DG are equipped with current limiters which can limit the fault current during fault conditions [9]. Thus, it is expected that the PCI for inverter based DG will be even higher than the values calculated for synchronous-based DG. In addition, in protection coordination studies [18]–[23], all loads are assumed to be static loads. Static loads do not have fault current contribution and for this reason the effect of load is commonly neglected in protection coordination studies. On the contrary, dynamic loads (such as motors) can contribute to fault current. The effect of dynamic loads has not been considered in this paper but it is worthy to mention that the presence of dynamic loads can impact the DG penetration level as well as PCI.

VI. Conclusions

This paper proposes a new protection coordination index (PCI) for quantifying impacts of interconnecting DG on protection coordination. The PCI is calculated by optimally determining the rate of change of DG penetration level with respect to the coordination time interval. A two-phase optimization problem is proposed, implemented and tested on the power distribution side of the IEEE 14-bus and IEEE 30-bus systems. The results show that the proposed PCI can serve as an effective measure for utility operators to determine the best location for allocating a utility owned DG with minimal impact on the protection coordination. Furthermore, the PCI can also help in determining the extent to which the system protection coordination is affected with the installation of customer owned DG and thus identifying any necessities for modifying the relay settings as a result of the DG integration. Lastly, the results showed that a DG installed at a certain location can either increase or decrease the PCI value at other locations.

Appendix I

The single-line diagram of the IEEE 14-bus looped distribution system is shown in Fig. 13. The detailed data for the IEEE 14-bus test system can be obtained from [24]. The distribution system is fed through two 60 MVA 132 kV/33 kV transformers connected at buses 1 and 2. All seven buses have been selected as candidate locations for DG installation. All DG units are connected to the system through a 480 V/33 kV step-up transformer with 0.05 p.u transient reactance. The system is equipped with 16 directional over-current relays, two on each side of a line. The short circuit currents are calculated by conducting a bolted three-phase midway fault on each line. The fault locations are denoted as F8 to F15 as shown in Fig. 13.

Appendix II

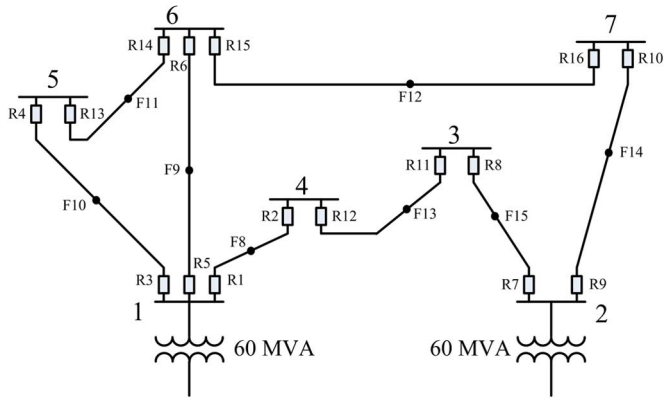

Fig. 13. Power distribution system of the IEEE 14-bus system under study.

TABLE V
OPTIMAL RELAY TDS AND IP SETTINGS FOR IEEE 14-BUS CASE

Relay	*TDS(s)*	*Ip(p.u)*	*Relay*	*TDS(s)*	*Ip(p.u)*
1	0.05	0.8267	9	0.05	0.6195
2	0.05	0.3500	10	0.05	0.2602
3	0.05	0.5584	11	0.05	0.6499
4	0.1528	0.0343	12	0.05	0.5275
5	0.05	0.6953	13	0.1094	0.0888
6	0.05	0.1296	14	0.05	0.4004
7	0.05	1.0772	15	0.05	0.4718
8	0.05	0.2270	16	0.05	0.3271

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