Overcurrent relay coordination with grid-connected and islanding capability on distribution network with distributed generation

Adrianti¹, S Wahyuni¹, and M Nasir¹
¹Electrical Engineering Department, Universitas Andalas, Padang, Indonesia

E-mail: adrianti@eng.unand.ac.id

Abstract. Islanding operation of distributed generation becomes a more appealing operation since large numbers of distributed generation have been installed worldwide. Islanding operation can improve the network reliability as the distributed generation continues providing electrical power for consumers when grid outages occur. However, the protection scheme for the islanding condition is one factor that hinders the realization. The setting of overcurrent relays on distribution network is calculated based on grid-connected condition hence the relay often fails to protect the network during islanding condition. Therefore, this paper proposes a method to establish overcurrent relay settings that coordinate correctly for both islanding and grid connected. The method tries to find a compromise between the setting for grid-connected and grid disconnected condition. The results of a case study show that method has successfully obtained a setting which provides correct coordination of the standard inverse overcurrent relay for both grid-connected an islanding condition.

1. Introduction
Installation of Distributed Generation (DG) brings challenges for power system protection engineers. DGs change current direction and magnitude on the distribution network hence the existing power system protection may fail to provide the expected level of protection and coordination [1]. Therefore, reconfiguration and resetting of the protection system have to be carried out after installation of DG/DGs [2].

DG can improve the reliability of distribution networks as it can continue supplying consumers during grid outages which are called islanding operation of DG. The islanding operation occurs during grid outage due to breakers operation for clearing faults hence often called an unintended islanding operation. The unintended islanding operation is avoided by Distribution Network Operator because of several reasons including the risk of protection coordination failure. Since the existing protection system on the distribution network is not designed for islanding condition, it may fail to detect the faults, operate slower than it should be or mal-operate [1]. As a result, DGs must be disconnected from the network following grid disconnection. Therefore, a protection scheme that detects grid disconnection event and then disconnects the DGs become compulsory for a DG that connected to distribution networks [3, 4]. This type of protection is called anti-islanding protection. The most popular anti-islanding protection works based on the rate of change of frequency in the network. However, this protection often produce unwanted operation due to frequency change which is not caused by grid disconnection such as large generator lost in the power system.
A significant amount of DGs operate worldwide today, the the unwanted operation of anti-islanding protection has brought mass tripping of DGs and may lead to power system blackout [1, 5]. The consequences, transmission system operator is trying to relax the setting of anti-islanding protection to prevent unwanted disconnection of DGs. Thus, if the DG islanding operation is allowed, anti-islanding protection will be no longer required, and the problem of mass DG tripping will be overcome.

As islanding operation of DG(s) has several advantages, the obstacles that prevent its operation should be solved. Therefore, the degradation of protection system performance during islanding will be the focus of this paper. This paper is aimed to find settings of overcurrent relays on distribution networks that provide correct coordination for both grid-connected an islanding condition.

Adaptive settings are proposed in several kinds of literature [6, 7] to overcome failures and mal-operations of overcurrent relays due to the changes of magnitude and direction of current during grid connected and islanding condition. However, the adaptive setting required expensive equipment such as a detection system to detect the change of network condition (grid connected or islanding) and communication system. This equipment may not cost-effective for small DGs.

Although the magnitude and direction of current change due to grid-connected an islanding condition, the current differences between these two conditions may not be very big, the differences are influenced by the capacity of synchronous DGs and DG location [8]. Therefore, it may be found that the overcurrent relays setting does not vary significantly for grid-connected an islanding condition. Moreover, current settings of overcurrent relays are usually calculated based on maximum normal currents hence they can provide a wide margin to minimum fault currents [9]. Depend on the capacity and location of DGs, the wide margin of the relay setting may able to accommodate both grid connected and islanding condition using only one setting. Thus, it will provide a cost-effective protection system for relative small DGs. In this paper, this hypothesis is tried to be proved using a case study. A proposed method for verifying the hypothesis is explained in the following section.

2. The proposed method
The proposed method for finding a single overcurrent relay (OCR) setting which can work for both grid-connected and islanding condition on distribution network with DG is shown in a flowchart in Figure 1. The method starts with the setting for grid-connected condition (called setting 1). If setting 1 fails to coordinate for islanding condition then create setting 2 that is calculated based on islanding condition. The setting 2 is tested for both islanding and grid connected with their variation such as loss of a load point. For grid-connected, the settings are also tested for a condition where the DG is out services. If setting 2 fails to coordinate for one of the condition, then a compromise setting have to be created. The compromise set is a combination of both setting 1 and setting 2 and obtained using try and error concept.

For a case study where fault current magnitude varies very significantly between grid-connected and islanding condition, the method may find that no single setting is suitable for the OCR. For this kind of network, the proposed method will not be a suitable method.
Figure 1. Flowchart of finding single settings for OCR on distribution network with DGs
3. Result and Discussion
The proposed method has been implemented in a case study shown in Figure 2. The case study is a distribution network supplied by a 150 kV grid that connected to 150/20 kV transformer. The network serves four load point. Asynchronous generator type DG is installed downstream of the network at bus 6. Four feeders and nine OCR (R1 to R9) also serve the network. The OCRs are standard inverse type. Data of the case study are shown in table 1.

![Figure 2. Single line diagram of a distribution network case study [2]](image)

| Network Component Parameter | Magnitude |
|-----------------------------|-----------|
| Grid’s short circuit MVA    | 619.195 MVA |
| Line impedance from bus 3 to bus 4 | 3.2819 + j 5.0170 Ohm |
| Line impedance from bus 3 to bus 5 | 5.2969 + j 8.0973 Ohm |
| Line impedance from bus 3 to bus 6 | 3.456 + j 2.679 Ohm |
Setting 1 of relay R1 to R9, shown in table 2, have been verified for the grid-connected condition.

**Table 2.** The setting of the OCR for grid-connected condition (setting 1).

| Relay | CT ratio | Direction | Current setting (A) | TMS |
|-------|----------|-----------|---------------------|-----|
| R9    | 60:5     | -         | 1.063               | 0.318 |
| R8    | 60:5     | -         | 1.192               | 0.1  |
| R7    | 60:5     | Reverse   | 1.063               | 0.1  |
| R6    | 60:5     | Forward   | 0.44                | 0.527 |
| R5    | 100:5    | -         | 1.458               | 0.1  |
| R4    | 100:5    | -         | 1.579               | 0.1  |
| R3    | 400:5    | -         | 0.792               | 0.727 |
| R2    | 100:5    | -         | 0.105               | 0.1  |
| R1    | 400:5    | -         | 8.91                | 1.059 |

For islanding condition, DG’s capacity cannot balance with all load point. Therefore load 2 and load 4 have to be shed from the network. Thus, only load 1, load 3 and their respective feeder are energized from the DG. As a result, only R4, R7, R8 and R9 will be needed to protect the network for the islanding condition. Settings 1 of these four relays is evaluated for islanding condition. The result shows that when a fault occurs on the line between bus 3 and bus 4, R7 trips before the nearest relay, i.e. R4. This coordination failure also depicted in relays coordination curve in Figure 3, which shows there are intersections on the coordination curves of the three relays. This indicates that coordination among the three relays fails to be achieved. As consequences, setting 1 cannot be applied for islanding condition.
The variances of three-phase fault current between grid-connected and islanding condition are shown in figure 4. A fault at the beginning feeder between bus 3 to bus 4 is seen by R4 vary significantly for grid-connected an islanding condition. The less current magnitude during islanding condition has caused R4 to work slower than it should be. From the graph of maximum normal current seen by the relays in figure 5, can be seen that no significant decrease of normal current seen by R4. For R7, it sees the unchanged current magnitude of fault current as depicted in figure 4 but experiences a quite significant increase in the maximum normal current (figure 5).

Figure 3. Setting 1 coordination curve of R4, R7, and R9 for a fault on feeder between bus 3 to bus

Figure 4. The currents that seen by the relays for a three-phase fault at the beginning feeder between bus 3 to bus 4.
Figure 5. Maximum Normal currents seen by relays for grid-connected and islanding condition

The setting for islanding condition (setting 2) is then calculated using normal and fault current during islanding. Settings for islanding condition are shown in table 3.

| Relays | CT ratio | Current setting (A) | TMS |
|--------|----------|---------------------|-----|
| R4     | 100:5    | 1.562               | 0.1 |
| R8     | 60:5     | 1.192               | 0.1 |
| R7     | 60:5     | 2.603               | 0.274 |
| R9     | 60:5     | 3.786               | 0.392 |

The setting 2 has been tested for islanding condition and success in providing coordination. The setting 2 is also tested for grid-connected condition alongside setting 1 for other relays that not work during islanding. The results show that the relays provide coordination as intended to. Coordination problem among R4, R7, and R9 for a fault at the feeder from bus 3 to bus 4 has been solved. Relay coordination curves show this for setting 2 in figure 6.
4. Conclusion
From the settings evaluation, it can be concluded that for this case study, the setting obtained from islanding condition can be used for both grid-connected an islanding condition. The proposed method has successfully established a setting that works correctly for both grid condition.

The future work will continue with several different case studies hence from the case studies a general conclusion can be obtained. The conclusion will list requirements of networks with DGs that suitable for the application of the proposed method and typical networks that cannot have one setting for both grid-connected conditions.

5. Acknowledgments
Authors would like to thank the Electrical Engineering Department, Universitas Andalas, for providing financial support for this research with contract number 076/UN.16.09.D/PL/2018.
References

[1] M H Bollen and F Hassan 2011 *Integration of distributed generation in the power system* vol. 80: John Wiley & Sons.

[2] Adrianti and N Mukhlisiah 2017 Rekonfigurasi Relai Proteksi Setelah Penambahan Pembangkit Tersebar pada Jaringan Distribusi *Jurnal Nasional Teknik Elektro*, vol. 6, Juli 2017.

[3] ENA G59 2010, *Recommendation for the Connection of Generating Plant to the Distribution Systems of Licensed Distribution Network Operators*, ENA G59.

[4] PLN 2014, *Pedoman Penyambungan Pembangkit Listrik Energi Terbarukan ke Sistem Distribusi PLN*.

[5] National Grid 2009 Report of the National Grid Investigation into the Frequency Deviation and Automatic Demand Disconnection that occurred on the 27 May 2008 London.

[6] P Mahat, Z Chen, B Bak-Jensen and C L Bak 2011 A Simple Adaptive Overcurrent Protection of Distribution Systems With Distributed Generation *IEEE Transactions on Smart Grid*, vol. 2, pp. 428-437.

[7] S M Brahma and A A Girgis 2004 Development of Adaptive Protection Scheme for Distribution Systems with High Penetration of Distributed Generation *IEEE Transaction on Power Delivery*, vol. 19, pp. 56-63.

[8] A Adrianti 2015 A Risk Assessment Framework for Power System Protection Ph.D., Electronic and Electrical Engineering, University of Strathclyde, Glasgow.

[9] Y G Paithankar and S R Bhide 2010 *Fundamentals of power system protection*. New Delhi: PHI Learning Private Limited.