Electric Power Systems Research 130 (2016) 124–131

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Method for distributed generation anti-islanding protection based on singular value decomposition and linear discrimination analysis

G. Marchesan*, M.R. Muraro, G. Cardoso Jr, L. Mariotto, C.D.L. da Silva

Federal University of Santa Maria, Brazil

ARTICLE INFO

Article history:
Received 8 June 2015
Received in revised form 23 July 2015
Accepted 28 August 2015
Available online 15 September 2015

Keywords:
Anti-islanding protection
Frequency oscillation
Distributed generation
Passive protection

ABSTRACT

Anti-islanding protection is one of the most important requirements for the connection of distributed generators in power systems. This paper proposes an algorithm to detect unintentional islanding in power systems with distributed generation. It is based on the singular value decomposition and linear discrimination analysis to differentiate frequency oscillations in synchronous generators caused by islanding from those caused by non-islanding events. The algorithm requires a very low number of mathematical operations, which is suitable for relay purposes. This is possible because most of the operations are in the training process and are made off-line. The performance of the proposed algorithm is evaluated for different scenarios and load conditions in IEEE 34 Node Test Feeder. The algorithm is able to detect islanding with active power mismatch of 1.6% of DG nominal power. The pattern recognition also prevents undue tripping, ensuring great robustness for the method.

1. Introduction

The distributed generation (DG) unintentional islanding can cause life-threatening, power quality deterioration, due to poor voltage and frequency regulation, and damage to system equipment and its loads. For these reasons, the islanded operation of distribution systems is normally not allowed and the anti-islanding protection is necessary for the connection of DGs to distribution networks. According to IEEE Std 1547 [1] islanding detection must occur up to 2 s after the island formation.

To avoid said problems, many power utilities request reclosers with transferred trip in the DG connection point. Other utilities request dedicated feeders with transfer trip. Although these communication-based methods are more effective than local techniques, they can suffer with communication problems and its implementation implies very high costs. The local methods were proposed as alternatives to methods based on communication and they can be divided into three categories: Active, hybrid and passive methods. The active methods inject small signals in the distribution system or force the DG to an abnormal situation, whilst the connection to the system keeps it under normal conditions. In general these methods have a small non detection zone (NDZ); however, the disturbances inserted in the distribution system may cause power quality deterioration [2,3]. If the distribution system has multiple generators connected very close to others with similar techniques, they might cause interference into each other and impair the performance of these techniques. In [4] the performances of active frequency drifty methods are evaluated for multi inverter system. The non-detection zone increases when the inverters try to drift the frequency in opposite directions. In [5] an alternative solution for the interference problem has been proposed for inverter based generations. The method injects a high frequency signal in a master inverter and this signal is used in all other slave inverters for island detection. The slaves operate in a cancelation mode avoiding interference between inverters. Other solution for multi-DG was proposed in [6]. The method aims to estimate overall transient stiffness to distinguish prior- and post-islanding. Each DG perturbs the system at different frequency, thus avoiding the interference inter DG; however, these perturbations can also cause power quality deterioration. An average absolute frequency deviation value based active islanding detection technique is proposed in [7]. The method has zero NDZ, detects stable island formation without forcing the island to lose its stable operation, and has a detection time up to 100 ms, however, the tolerance to short circuits is not evaluated yet.

Due to lower cost of passive methods, it is common the use of anti-islanding schemes using protection functions such as the rate of change of frequency (ROCOF) [8], which is one of the

* Corresponding author. Tel.: +55 5599072819.
E-mail address: gutomarchesan@gmail.com (G. Marchesan).

http://dx.doi.org/10.1016/j.epsr.2015.08.025
0378-7796/

fastest passive protection algorithms used in relays for islanding detection. Other techniques such as under/over-frequency, under/over-voltage [9], and vector-surge [8] are also used, although these techniques are effective for islanding conditions with large power imbalance, passive methods may fail or spend too much time detecting low power imbalance. In addition, events like short circuits and switching of large blocks of load can cause islanding erroneous islanding detection. In [10], an Island detection method for inverter connected generators based on a dynamic estimator is proposed, which measures the current amplitude and phase.

Aiming to get the best sides of active and passive methods, the hybrid methods often use a passive method that identifies a transient condition and the DG starts to cause a disturbance to destabilize parameters in case of islanding. Hybrid techniques also have been proposed [11]. The technique changes GD active power only when it cannot differentiate clearly islanding from other events, thus making the islanding detection easier. In [12], the method uses a ROCOF relay to decide when the DG frequency set is changed. The main problem with hybrid methods is they still depend on passive method threshold.

A passive technique based on decision tree was proposed in [13], but it uses a very large set of parameters which hinders its implementation. Wavelet has also been used in an intelligent technique proposed in [14,15]. The wavelets extract voltage and current features and use a decision tree to identify the islanding. The method proposed by [14] uses a very large data set for training, which is a hard work considering that the method should be retrained at each topology change. In [16], a wavelet design for island detection is proposed. The algorithm is simpler than [14,15] and has lower computational effort using only the voltage and six wavelet coefficients.

Techniques based on synchronous machine oscillation frequency estimation are proposed by [17,18]. The methods respectively use windows of 350 ms and 500 ms for estimating damping and oscillation frequency estimation, which demand too much time for islanding detection purposes. The method proposed in [17] aims to estimate the signal parameters using a TLS-ESPRIT algorithm. The method needs to minimize a cost function which demands a relatively high processing time. In [18], a different solution for estimating damping and frequency of oscillation is proposed using Tufts–Kumaresan method. The method of [18] is not recursive, requiring much less computational effort; however, given its large window, the island detection time is more than 600 ms. Although it may be less than the 2 s required by IEEE standard 1547 [1] this island detection time may be greater than recloser time. In general, utilities use auto reclosing times around 500 ms, which can result in out of synchronism reclosing.

In this paper, a faster algorithm using smaller windows than previous methods is proposed. As well as [17,18], the proposed methodology uses the oscillation frequency to characterize islanding. However, the proposed methods do not use the value of the oscillation frequency, but the shape of the electrical frequency. In other words, the adopted strategy is to use the well-known information that during islanding the frequency behaves like an exponential or a low-frequency oscillation due to the governor effect. During events where the DG is connected to the system, like short circuits and load switching, the frequency oscillates at the damped natural frequency. The frequency is decomposed using singular value decomposition (SVD), and its components are analyzed with linear discrimination analysis (LDA) using the generalized Rayleigh quotient. The main contribution of proposed technique is an improvement in speed when compared with [17,18]. This was possible since the approach uses a pattern recognition technique with a small window, providing a faster detection.

In the following sections, the mathematical fundamentals regarding synchronous machine model, SVD, LDA, and the proposed algorithm are presented, along with the simulations results.

2. Synchronous machine models

On a synchronous machine operating in steady state, the relative position between rotor and resulting magnetic field remain almost constant. When a sudden disturbance occurs, the angle between them oscillates dynamically according to the swing equation given by (1).

$$\frac{2H}{\omega_0}\frac{d^2\delta}{dt^2} + D\frac{d\delta}{dt} = P_m - P_e \quad (1)$$

where δ is the relative rotor angle, t is the time, H is the generator inertia constant, D is the damping coefficient, ω_0 is the DG synchronous speed, and P_m and P_e are mechanical input and electric power output of the DG, respectively.

2.1. Frequency variation during non-islanding events

When a small disturbance occurs in the electrical system, the DG oscillates and returns to its original state after some time. The electrical power injected by DG in the distribution system can be written as

$$P_e = P_{max}\sin\delta \quad (2)$$

A small perturbation $\Delta\delta$ in δ, from the initial operating position δ_0 can be represented by

$$\delta = \delta_0 + \Delta\delta \quad (3)$$

Due to this perturbation, the swing equation (1) can be linearized and rewritten as

$$\frac{2H}{\omega_0}\frac{d^2\Delta\delta}{dt^2} + D\frac{d\Delta\delta}{dt} + P_s\Delta\delta = 0 \quad (4)$$

P_s is known as the synchronizing power coefficient and is defined by the equation

$$P_s = P_{max}\cos\ \delta_0 \quad (5)$$

Solving the differential equation shown in (4), [19] shows that the frequency deviation from nominal synchronous speed is given by (6).

$$\Delta\omega = \frac{d\Delta\delta}{dt} = -\frac{\omega_n\Delta\delta(0)}{\sqrt{1-\varsigma^2}}e^{-\varsigma\omega_n^t}\sin\omega_d^t \quad (6)$$

where

$$\omega_d = \omega_n\sqrt{1-\varsigma^2} \quad (7)$$

$$\varsigma = \frac{D}{2}\sqrt{\frac{\omega_0}{2HP_s}} \quad (8)$$

$$\omega_n = \sqrt{\frac{\omega_0}{2H}P_s} \quad (9)$$

From (6), one can see that the frequency is given by a damped sinusoidal waveform.

2.2. Frequency variation during islanding events

During an islanding event, the DG loses connection with the main system and, therefore, the synchronizing coefficient is 0. In this way, (4) can be rewritten as (10).

$$\frac{2H}{\omega_0}\frac{d^2\Delta\delta}{dt^2} + D\frac{d\Delta\delta}{dt} = \Delta P \quad (10)$$