Evaluating Unintentional Islanding Risks for a High Penetration PV Feeder

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Abstract—The continued adoption of DGs is quickly altering the composition of distribution systems (DSs). As the penetration and saturation of these new distributed generators (DGs) escalate, new challenges in the planning and operations of DSs are arising. At current penetration levels, DGs represent a rare or minimal threat to the stability of DSs. However, in a future with high saturation of DGs, the need for more thorough analysis and analysis is even more critical. Commonly used software applications in utility industry are not capable of analyzing the challenges, especially those requiring time-based analysis. This paper presents a simulation platform which enables utilities to evaluate the risk of unintentional islanding of interconnected DGs. The platform is simple to implement and fast, which means savings in cost and time of analysis. The platform can be used by the utilities’ engineers to facilitate the interconnection of DGs.

I. INTRODUCTION

Distribution systems (DSs) have been designed based on a vertical operating framework which is predicated on large central generations producing energy through transmission and substations to end-users. However, existing DSs may need to be prepared for accommodating distributed generators (DGs), implementing a non-vertical operating approach, and enabling end-users to participate in different market-based activities. Mandatory policies supporting energy resiliency and utilization of renewable energy resources, emphasize the need for personnel training and adapting existing data base. As mentioned earlier, utilities commonly use software applications, like CYME/CYMDIST, which are primarily used for steady state studies. Those software applications can provide already structured database of load information, layout of the electrical distribution system, and the different electrical parameters of the network equipment. It would be desirable to link existing electric power simulation tools with innovative approaches and perform required analysis.

Anti-islanding or loss-of-main-grid protection is an important aspect of protection related challenges of DGs interconnection. Islanding can be defined as a condition in which a portion of the utility system contains both load and DG, remains energized while being isolated from the remainder of DS [4]. Due to safety and transient stability concerns, IEEE 1547 (2003) requires that the loss-of-main-grid must be detected by DGs within 2 seconds and must lead to immediate trip of the DGs from DS. Although DGs are equipped by anti-islanding schemes, those schemes are not 100% reliable. They present an inherent operating region, characterized by small power imbalances in an islanded system, where they can lead to detection failure. The corresponding system operating conditions are called non-detection zone (NDZ) and the islanding detection failure is named unintentional islanding [6].

From the utility stand point, identifying NDZs is very important because they may violate the IEEE 1547 standard requirements for unintentional islanding. Therefore, an analytical tool which can perform in-depth and sufficiently rigorous islanding analysis, could help utilities to assess the risk of unintentional islanding in more reliable and cost-effective fashion and also facilitate interconnection of DGs in a safer manner. In this paper, a simulation platform is presented which can help utility companies to assess the risk of unintentional islanding of interconnected DGs. The platform is simple to implement and fast, which means savings in cost and time of islanding studies. The platform can be used in a plug and play fashion with any kind of anti-islanding schemes used by DGs’ manufacturer.
II. INTERCONNECTION SCREENING

Interconnection procedures may vary depending on the state or federal jurisdiction, and implementation practices may change by the utility. Several screening procedure have been reported in the literature, such as the Sandia guideline [7]. The guideline, based on a four-step procedure, indicates when the risk of islanding may not be negligible.

All screening procedures are used to avoid in-depth additional study to assess the risk of unintentional islanding of a proposed DG system. However, considering the rapid saturation of DGs, it is expected that existing simplified screening approaches could not address the risk. Therefore an in-depth study seems necessary. In order to reduce the time and cost of DG systems’ installation, the study should be effective and easy to implement. An analytical tool which can leverage current utilities’ practices and software applications to conduct islanding studies can perform the task in a cost-effective manner. The analytical tool must be able to model all components of the DS including distribution feeder, transformers, loads, and DGs. The following section presents the approach used in the developed analytical tool to model the distribution feeder.

III. DISTRIBUTION FEEDER MODELING

DGs are connected to distribution feeders, therefore generating an accurate model of the feeder is the first step in the simulation platform. However, the size of the feeders and number of elements in the feeders make this step complex and time consuming. In this section a simple algorithm is presented to model the distribution feeder from the substation to the end nodes of the feeder.

The utilities’ commonly-used software applications, such as CYME/CYMDIST, use the feeder data for different simulations. The data has been defined and structured specifically for each software application. Therefore, integrating the feeder’s raw data into the platform results in an analytical tool which can interact with many software applications. To do so, the tool must translate the raw data into the accurate feeder model. The raw data includes nodes, lines (three-phase or single phase line which could be underground or overhead cables), transformers, capacitor banks, regulators, and loads. Each component is identified by a unique ID. Creating the feeder topology and detecting the nodes’ and other components’ connectivity is the key element in distribution feeder modeling.

A simple algorithm has been used in the developed tool to detect distribution feeder topology, nodes’ connectivity, and all paths from the substation to the end nodes of the feeder [8]. The algorithm which can be applied to radial and normally open-loop DSs with any size and number of nodes, works based on the graph theory. A radial DS can be considered as a tree graph $G$ which is connected and has no loop. Therefore the distribution feeder can be modeled as a connected directed tree graph with $n$ vertices and $n-1$ edges. A color can then be assigned to each node, using the coloring approach by Welsh and Powell [9]. The algorithm then detects the connectivity of all nodes and generates the accurate topology of the feeder by tracking the assigned colors of nodes.

At this point, the tool has modeled the distribution feeder. The next step is to model interconnected DGs.

IV. DG MODELING

Among all DG technologies, photovoltaic (PV) systems have attracted considerable attention and investment in several countries such that a significant penetration of PV energy into the DS is anticipated. Therefore, the focus of this paper is on PV systems. A PV system includes a PV generator (consisting of many PV panels) along with a boost DC/DC converter connected to the DC side of a three-phase (3ph) DC/AC converter, a LC low-pass filter which is connected to the AC side of the 3ph DC/AC converter, and an isolation transformer to connect the rest of the system to the grid. The DC/AC converter is considered as a voltage-sourced converter (VSC) in this paper.

For faster simulations, considering the complexity of the DS, an equivalent dynamic average-value model was used. In such a model, which is known as averaged model, instead of applying switching scheme, terminal variables of the VSC are approximated by their respective per-switching-cycle moving average values [10]. An important feature of a grid-connected PV system is the synchronization which identifies the angle of the grid voltage and can be achieved with variety of methods. A phase locked loop control system based on the model provided by [11], was used for synchronization purpose. Assuming a fixed input DC power at DC side of the VSC, the variation in sun irradiations and its effect on DC-link voltage could be ignored for islanding study purposes. Also based on current practices in utilities, PVS are not allowed to perform voltage regulation, instead voltage and frequency is regulated by the grid. Therefore, the real and reactive power control scheme presented by [10] was used in this paper. It is worth noting that due to the ongoing cost-performance improvement in power electronics and controls, IEEE 1547A (2014) standard allows DGs to regulate voltage by changing their active and reactive power, ride through abnormalities of grid voltage, and provide modulated power as a function of frequency. In response to the standard, few utility companies considering the voltage regulation by DGs. In those cases, the PV model can be modified to enable DGs for voltage regulation.

Islanding detection method (IDM) is another important feature of PV systems. Local IDMs are classified as passive and active techniques. Passive IDMs rely on non-perturbed measurements such as frequency and voltage to detect islanding condition. Over/under frequency protection (OFP/UFP) and over/under voltage (OVP/UVP) are examples of commonly used passive methods. On the other hand, a perturbation is used in active IDMs to drift the frequency or voltage beyond certain threshold values.

In voltage (frequency) feedback approach, when the inverter-sensed output voltage (frequency) is increasing, the anti-islanding feedback will command the inverter active (reactive) power output to be increased. In the absence of the stiff grid, the voltage (frequency) will keep increasing in order to balance the active (reactive) power. The increased voltage (frequency) will further drive the inverter active (reactive) power up due to the anti-islanding feedback. As a result, the voltage (frequency) will be eventually out of the nominal ranges so that the islanding can be detected. Similar but opposite destabilization occurs when the sensed voltage (frequency) is decreasing initially. The most widely used active IDMs are Sandia frequency shift (SFS) and slip-mode frequency shift (SMS). The basic idea behind SFS and SMS IDM is to
introduce a small increase or decrease in the current frequency of the inverter. The positive feedback mechanism enables the inverter to push the frequency in the same direction as the disturbance. In the absence of the stiff grid, the deviation in the voltage frequency measured at the terminal increases which results in indication of the occurrence an islanding event [12].

**A. SFS IDM**

SFS is based on the use of one zero-current segment \( t_z \) per line semicycle [13]. A positive feedback is used to increase the chopping factor \( cf \), which is defined as the ratio of the zero time \( t_z \) to half of the period of the voltage waveform \( T_v/2 \). Thus \( cf = 2t_z/T_v \) with increasing the deviation of the frequency away from nominal. The increasing deviation is usually selected to be a linear function of the frequency of the voltage at the point of common coupling (PCC) which is denoted by \( f \). The function is as follows [14]:

\[
 cf = cf_0 + K(f - f_g),
\]

where \( cf_0 \) is the chopping fraction when there is no frequency error, \( K \) is an accelerating gain, and \( f_g \) is the grid frequency. The inverter angle for the SFS IDM \( \theta_{SFS} \) can be calculated as follows [15]:

\[
 \theta_{SFS}(f) = \omega t_z/2 = \frac{\pi cf(f)}{2}.
\]

The non-detection zone (NDZ) of the SFS IDM in the quality factor, \( Q_f \), versus resonant frequency, \( f_0 \), space is derived using the phase criteria [15]:

\[
 \tan^{-1} \left[ Q_f \left( \frac{f_0}{f_{is}} - \frac{f_{is}}{f_0} \right) \right] = \frac{\pi}{2} [cf_0 + K(f - f_0)].
\]

**B. SMS IDM**

SMS method applies positive feedback to the phase of the voltage at the PCC as a means of shifting the phase and hence the short-term frequency [16]. The phase angle of the current is controlled as a function of the deviation of the frequency of the last cycle from the nominal operating frequency of the utility grid. The phase angle of the PV inverter current, \( \theta_{SMS} \), is calculated as follows [15]:

\[
 \theta_{SMS}(f) = \theta_m \sin \left( \frac{\pi}{2} f - \frac{f_g}{2} \right),
\]

where \( f_m \) is the frequency at which the maximum phase shift \( \theta_m \) occurs. After grid disconnection, the frequency of the islanded system will drift from the rated value \( f_g \) if [15]:

\[
 \frac{d\theta_{load}}{df}|_{f = f_g} < \frac{d\theta_{SMS}}{df}|_{f = f_g}.
\]

Thus, the following equation can be derived for the SMS active frequency drifting [16].

\[
 \frac{\theta_m}{f_m - f_g} \geq \frac{12Q_f}{\pi^2},
\]

where \( f_m - f_g \) is usually taken as 3 Hz so that stable operating points lie outside the normal frequency range.

The NDZ of the SMS IDM in the \( Q_f \) versus \( f_0 \) space is derived using the phase criteria [17]:

\[
 \tan^{-1} \left[ Q_f \left( \frac{f_0}{f_{is}} - \frac{f_{is}}{f_0} \right) \right] = \theta_m \sin \left( \frac{\pi}{2} \frac{f - f_g}{f_m - f_g} \right).
\]

After understanding the feeder and DG model, next the procedure used in the developed platform to calculate the NDZ is presented.

**V. EVALUATION OF RISK OF UNINTENTIONAL ISLANDING**

Considering the PV output active and reactive power as \( P \) and \( Q \), respectively, and the load active and reactive power as \( P_L \) and \( Q_L \), respectively, Fig. 1 shows the schematic diagram of a distribution feeder. As can be seen from the figure, the mismatch between generation and consumption in the feeder, shown by \( \Delta P + j\Delta Q \), is compensated by the grid.

\[
 f = \frac{1}{2\pi \sqrt{LC}} \left( \sqrt{\left( \frac{Q_L}{Q_f P_L} \right)^2 + 4 - \frac{Q_L}{Q_f P_L}} \right).
\]

The behavior of the system at the time of utility disconnection will depend on \( \Delta P \) and \( \Delta Q \) just before the disconnection. If \( \Delta P = \Delta Q = 0 \) when the utility is disconnected, there might not be sufficient change in the voltage amplitude or frequency at PCC to activate local IDMs. Calculation of NDZ in terms of \( \Delta P \) and \( \Delta Q \) might not provide a transparent view of the feeder loading condition. Therefore, the NDZ is defined based on the load fraction \( LF \) and power factor \( PF \) of the feeder. \( LF \) denotes the fraction of the feeder’s load over the feeder’s peak load.

Based on the formed island, its load, and interconnected DGs, one can find the balance point at which the active/reactive power generation matches the active/reactive power consumption. This balance point is denoted by \( LF^* \) and \( PF^* \) and calculated as follows:

\[
 LF^* = \sqrt{\frac{P^2 + (Q + Q_{cap})^2}{P_L^2 + Q_L^2}},
\]

\[
 PF^* = \frac{P}{\sqrt{P^2 + (Q + Q_{cap})^2}},
\]

where \( Q_{cap} \) stands for reactive power injection by capacitor banks. Notice that in the above equations, \( P \) and \( Q \) represent the aggregated DG plants’ generation capacity in the case of several interconnected DGs.

Fig. 2 shows a simple presentation of the developed platform. After generating the feeder model and calculating the
balance point \((LF^*, PF^*)\), a batch-mode coarse resolution sweep is run over the expected range of \(LF\) and \(PF\) (the loop in the figure). For all pairs \(LF\) and \(PF\) in the batch, a simulation is run in which an island is formed due to the loss-of-main grid and the resulting run-on time of all DG plants in the island is recorded. Notice that the run-on time of a DG plant is defined as the time lag between occurrence of the loss-of-main grid and the DG plant disconnection caused by its islanding protection. The NDZ is defined as the range of loads over which the run-on times of the DG plant are longer than the IEEE 1547 limit of 2 sec. Once any NDZ is located, batches utilizing finer resolution are run to determine the peak run-on time values and refine the prediction of the shape of the NDZ in the \(LF-PF\) plane. Once the NDZ is known, utility engineers can decide whether the NDZ is such that the risk of islanding is negligible or it represents a realistic feeder’s loading scenario and additional mitigation is needed.

![Flowchart of developed analytical tool for islanding study.](image)

**VI. RESULTS AND DISCUSSION**

The developed analytical platform was tested on an actual case study. The case study represents a distribution feeder in National Grid USA operating region in Northeastern U.S. The feeder is a four-wire multi-grounded neutral overhead distribution feeder operated at 13.2 kV, as shown in Fig. 3. The voltage levels for step down transformers in the figure are in kV. The feeder contains 1438 nodes, 1437 branches, 2 fixed shunt capacitor banks, and 4 transformers. The feeders measured peak daytime load during the past twelve months was approximately 9.469 MVA, and the daytime minimum load was measured to be approximately 3.0 MVA, which is slightly less than \(1/3\) of the peak load. Two PV plants, PV plant 1 and PV plant 2, were connected to the feeder. PV plant 1 is composed of 6 inverter modules, each with 500 kW capacity. The total capacity of PV plant 1 is 3 MW. PV plant 2 is composed of 4 inverter modules, each with 500 kW capacity. The total capacity of PV plant 2 is 2 MW. Both PV plants are connected to the feeder with a step up 0.32 kV/13.2 kV transformer. Table I lists the set-point values for UFP/OFP and UVP/OVP of the PV plants. It is assumed that both PV plants are equipped by SFS IDM.

The feeder raw data used for simulations was acquired from the existing feeder’s CYME file. The data was then processed and the accurate model of the feeder with all components was generated in the developed platform. MATLAB/SIMULINK was utilized as the main platform.

Fig. 4 shows the run-on time over a range of \(LF\) and \(PF\). As can be seen from the figure, the maximum run-on time is 1.8 second. The range of \(LF\) and \(PF\) in which the maximum run-on time occurs are 0.57 to 0.61 and 0.968 to 0.972, respectively. The \(LF\) range for 1.8 second run-on time is higher than the feeder minimum \(LF\) and the \(PF\) range for 1.8 second run-on time is a realistic range to happen. Therefore the risk of experiencing 1.8 second run-on time upon the loss-of-main grid is high. Since 1.8 second run-on time is too close to 2 second requirement, a conservative approach might require additional protection in order to avoid any possibility of unintentional islanding.

![Run-on time (in Second) of the PV plants.](image)

**TABLE I. VOLTAGE AND FREQUENCY TRIP SET-POINTS OF THE PV PLANTS IN THE CASE STUDY.**

<table>
<thead>
<tr>
<th>Element</th>
<th>Pickup Range</th>
<th>Time Delay</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under Voltage</td>
<td>0.5 pu</td>
<td>160 ms</td>
</tr>
<tr>
<td>Under Voltage</td>
<td>0.88 pu</td>
<td>2 s</td>
</tr>
<tr>
<td>Over Voltage</td>
<td>1.1 pu</td>
<td>1 s</td>
</tr>
<tr>
<td>Over Voltage</td>
<td>1.2 pu</td>
<td>160 ms</td>
</tr>
<tr>
<td>Under Frequency</td>
<td>57 Hz</td>
<td>160 ms</td>
</tr>
<tr>
<td>Over Frequency</td>
<td>60.5 Hz</td>
<td>160 ms</td>
</tr>
</tbody>
</table>

To illustrate the behavior of each PV plants after the loss-of-main grid, an operating point of \(LF=0.6\) and \(PF=0.9802\) is considered. Fig. 5 demonstrates the frequency at PCC of PV plants for considered \(LF\) and \(PF\). It is worth emphasizing that the rate of change of frequency at the PCC after the loss-of-main grid is lower when SFS IDM is not applied. In the absence of an active IDM, for the considered \(LF\) and \(PF\), both
PV plants will remain energizing for longer than 2 seconds.

Fig. 5. Frequency AT PCC of PV plants for $LF=0.6$ and $PF=0.9802$.

Fig. 6 shows the voltages at PCC of PV plant 2, after occurrence of the loss-of-main grid. Based on the figure and the set-points for UVP and OVP, it can be inferred that the reason for tripping the PV plants is the frequency.

![Image of frequency AT PCC of PV plants for LF=0.6 and PF=0.9802.](image)

From the simulation results, it can be observed that the developed analytical tool provides a platform for evaluating the risk of unintentional islanding of interconnected DGs. The platform incorporated the feeder raw data from the commonly-used utilities’ software applications and generated the accurate model of the feeder. Run-on time of each DG was then calculated for different loading conditions of the feeder. Calculated run-on time is then used by the utilities’ engineers to decide on additional protection in order to avoid any possibility of unintentional islanding.

**VII. CONCLUSION**

An analytical platform was presented in this paper which can provide an analytical tool for utilities to evaluate the risk of unintentional islanding of interconnected DGs. The platform utilizes the feeder raw data from utilities’ commonly-used software applications and generates an accurate model of the feeders in an automated fashion. The platform then calculates the run-on time of each interconnected DGs after the loss-of-main grid under different feeder’s operating conditions. Based on the calculated run-on time, the platform then finds possible feeder’s loading conditions under which the DGs may violate the IEEE 1547 requirement. Results can then be used by the utilities’ engineers to determine either the risk of islanding is negligible or it represents a realistic feeder’s loading scenario and additional mitigation is needed. The platform was used in a real case study and results indicate the simplicity, efficiency, and accuracy of the platform.

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**REFERENCES**


