ASSESSING THE IMPACT OF DISTRIBUTED GENERATION ON FEEDER PROTECTION

A Project

Presented to the faculty of the Department of Electrical and Electronic Engineering

California State University, Sacramento

Submitted in partial satisfaction of the requirements for the degree of

MASTER OF SCIENCE

in

Electrical and Electronic Engineering

by

Jonathan William Robinson

FALL
2016
ASSESSING THE IMPACT OF DISTRIBUTED GENERATION ON FEEDER PROTECTION

A Project

by

Jonathan William Robinson

Approved by:

__________________________________, Committee Chair
Atousa Yazdani

__________________________________, Second Reader
Mahyar Zarghami

__________________________________
Date
Student: Jonathan William Robinson

I certify that this student has met the requirements for format contained in the University format manual, and that this project is suitable for shelving in the Library and credit is to be awarded for the project.

__________________________, Graduate Coordinator
Preetham Kumar

Department of Electrical and Electronic Engineering
Abstract

of

ASSESSING THE IMPACT OF DISTRIBUTED GENERATION ON FEEDER PROTECTION

by

Jonathan William Robinson

Statement of Problem

The rise of renewable energy sources being attached to the distribution side of power systems is changing the way old radial protection schemes work. The purpose of this paper is to explore how Distributed Generation (DG) can change the timing operation of a system relay and how much the DG can change current magnitudes. These protection concerns are looked at and analyzed with the use of Power System Computer Aided Design (PSCAD) simulation to test a 24.9 kV, 34-bus feeder that is being supplied by a single source acting as a substation. Some results are presented and further research needs are acknowledged.

Sources of Data

The simulations were done with PSCAD and IEEE transaction papers were used for references.
Conclusions Reached

The addition of distributed generation on a feeder can change the sensitivity of protection relay trip timings and also increase the amount of current that goes to a fault, but at the same time decrease the amount of source current seen by the relay which could also lead to desensitized protection.

_______________________, Committee Chair
Atousa Yazdani

_______________________
Date
ACKNOWLEDGEMENTS

This project was finished with the help and support from my professors, family and friends. I would like to send my deepest thanks to all of them.

Specifically I would like to thank Professor Yazdani for being willing to work with me on the project and helping me with the PSCAD parts of it. I also want to thank Professor Kumar for putting up with my numerous questions about this project, but helping me get to the finish. On a less than specific note, I want to thank all the other CSUS Electrical and Electronic Engineering department professors for their various classes and help throughout my master’s education.

Finally, I would like to send my sincerest thanks to my family and friends for putting up with me during this time and who provided me with support. The success of this project and entire master’s program would not have been possible without them.
TABLE OF CONTENTS

Acknowledgements ........................................................................................................ vi
List of Figures .................................................................................................................. viii

Chapter

1. INTRODUCTION ........................................................................................................ 1
   1.1 Background of the Project ..................................................................................... 2
   1.2 Goals of the Project ............................................................................................... 3

2. TEST SYSTEM SETUP .............................................................................................. 4
   2.1 Distance Protection ............................................................................................... 5

3. SIMULATION RESULTS ............................................................................................ 7
   3.1 Relay Trip Time .................................................................................................... 7
      3.1.1 Fault Location #1 ......................................................................................... 8
      3.1.2 Fault Location #2 ......................................................................................... 9
      3.1.3 Fault Location #3 ......................................................................................... 10
   3.2 Impedance Relay Action ....................................................................................... 11
   3.3 System Current Changes ....................................................................................... 12
      3.3.1 Fault Location #1 ......................................................................................... 13
      3.3.2 Fault Location #2 ......................................................................................... 14
      3.3.3 Fault Location #3 ......................................................................................... 16
   3.4 Individual Generator Fault Currents .................................................................... 17

4. CONCLUSION ............................................................................................................ 19

References ..................................................................................................................... 21
# LIST OF FIGURES

<table>
<thead>
<tr>
<th>Figures</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>One-line Diagram of the Modified IEEE 34-Bus Feeder</td>
<td>4</td>
</tr>
<tr>
<td>2.</td>
<td>Mho-Based Characteristics of the Impedance Relay</td>
<td>6</td>
</tr>
<tr>
<td>3.</td>
<td>Breaker Trip Times for Fault Location #1</td>
<td>8</td>
</tr>
<tr>
<td>4.</td>
<td>Breaker Trip Times for Fault Location #2</td>
<td>9</td>
</tr>
<tr>
<td>5.</td>
<td>Breaker Trip Times for Fault Location #3</td>
<td>10</td>
</tr>
<tr>
<td>6.</td>
<td>RMS Source Currents for Fault Location #3</td>
<td>11</td>
</tr>
<tr>
<td>7.</td>
<td>RMS Source Voltages for Fault Location #3</td>
<td>12</td>
</tr>
<tr>
<td>8.</td>
<td>Maximum RMS Current Amounts for Fault #1</td>
<td>13</td>
</tr>
<tr>
<td>9.</td>
<td>Maximum RMS Current Amounts for Fault #2</td>
<td>15</td>
</tr>
<tr>
<td>10.</td>
<td>Maximum RMS Current Amounts for Fault #3</td>
<td>16</td>
</tr>
<tr>
<td>11.</td>
<td>RMS Fault Current Generator Contribution of Minimal DG (0.3 MW)</td>
<td>17</td>
</tr>
</tbody>
</table>
CHAPTER 1
INTRODUCTION

The main concept of Distributed Generation (DG) is to connect and utilize small power sources that are stationed at the consumer or distribution level with an electric power system (EPS). An EPS can consist of generation, transmission, sub-transmission, and distribution sections. DG can also be referred to as Distributed Resources (DR) since DG can include energy storage devices. Types of DR can consist of Photo Voltaic (PV) arrays or solar, diesel and gas fueled turbines, wind turbines, fuel cells, and energy storages [1].

Electric utilities would like to tap into these smaller power sources when there is an increase in electrical load as an alternative to generating or buying more bulk power from major power plants. Since DG supplied power is already located close to where it is needed, it does not need to be transported over a long distance to the costumer. Each DR source is typically built by small companies or individual homeowners, such as the case with solar, so electric utilities can increase their power supply without having to build new power plants. In addition, many of the DG sources that could be used are renewable energy types that can help reduce the use of fossil fuels for power generation.

The main engineering challenge for DR integration with an EPS is its effect on it and this is commonly referred to as its impact [2]. There are various ways that DG can change the EPS such as voltage regulation, frequency, potential islanding, and protection. The Application Guide for IEEE STD 1547 states that one of the problems that DR could have on a power system is that if it continued to supply power to a fault, it could affect the ability of EPS protection devices to detect the fault in the first place [2]. Therefore, every DG has the potential to change the power system
in unwanted and unsafe ways, which is why understanding how they can change the EPS is becoming a far more researched topic as the use of DG increases.

1.1. Background of the Project

As the use of distributed generation increases, so does its impact on the traditional protection schemes in distribution systems. Generally, conventional power systems work in a radial way, which is to say that power is generated at a power plant and then sent in one direction until it reaches the load or consumer [5]. Therefore, the typical protection scheme for a distribution feeder which can include fuses, reclosers, overcurrent and distance relays, is designed assuming that a fault current will increase current flowing in a single direction from the source to the fault location [3]. The addition of new DGs throughout a distribution feeder may interrupt the traditional protection of the system in unwanted ways such as:

1) Bi-Directional Fault Current: This is where multiple sources from different locations could contribute to the fault current causing it to become bi-directional which could result in a loss of relay sensitivity if the relay is insensitive to current direction [3].

2) Decreased/Increased Fault Current Seen by Relays: The added DG sources may end up increasing or decreasing the amount of current the relay sees [3].

3) Changing Fault Current Levels: DG can be variable sources such as PV and Wind turbines, which could mean that their power output can change significantly depending on the situation. Therefore, any traditional protections that may be based on a fixed amount may no longer function [3].

Thus, if DG caused any of these issues during a fault in the feeder it may lead to what is called “relay de-sensitization” which could lead to the relay failing to work as expected or at all [6]. As
a result, this particular topic is becoming a much more important and researched topic as the interest in DG grows.

1.2. Goals of the Project

For this project, the hope is to use a modified Power System Computer Aided Design (PSCAD) version of the IEEE 34-Bus test feeder created by Jen Z. Zhou, Dharshana Muthumuni, and Paul Wilson in the PSCAD computer simulator to analyze the changes that occur to a simple protection relay that is based on distance/impedance with mho-based characteristics. The relay will be positioned at the source of the feeder when multiple distributed generation sources are added throughout the system. These DG sources will be located at different feeder sections and multiple simulations will be conducted with varying DG amounts and fault locations. Each fault will be considered to be a single-line-to-ground fault as it is the most common fault type and it will also be measured as a bolted or zero resistance fault as it is the most severe fault amount possible. For each of the proposed cases, the time it takes for the relay to trip and the DG current contributions to the fault will be examined as well as how the fault and source current changes with each test. At the end, the hope is that some observations may be made and certain DG system impacts will be confirmed based on the findings of the simulations.
CHAPTER 2
TEST SYSTEM SETUP

As acknowledged previously, the test system used to determine the impact that DG could have on a feeder’s protection was the IEEE 34-Bus test feeder. Like the name implies, the feeder consisted of 34 Buses with different loads and other electrical components scattered throughout the branches. The basic system was then modified to include three distributed generators, their transformers and circuit breakers to connect them to the system, and finally another circuit breaker near the source or substation that would trip based on the relay protection. The modified one-line diagram of the IEEE 34-Bus system can be seen in figure 1.

As can be seen in figure 1, the protection breaker was positioned between bus numbers 800 and 802 near the main power source, which in real life would be a substation. Each distributed generator was placed at different locations around the feeder to give a more diverse sample of data when looking at its impact on the system. This is why DG number one was connected to bus number 828, DG number two was connected to bus number 844, and DG number three was
connected to bus number 862. Figure 1 also shows the locations of the faults applied during testing for a visual reference. Like the distributed generators, the faults were applied at different positions to get a more diverse selection of results. This is why fault number one was near the source and start of the feeder, fault number two was somewhat spaced equally between the DG’s and near the middle of the feeder, and fault number three was close to a DG and near the end of the feeder.

For the actual testing of the feeder, three different scenarios were looked at with various DG amounts. The source was set to be a three-phase infinite bus with specifications of having a 24.9 kV line-to-line voltage, a frequency of 60 Hz, and a maximum power output of 12 MVA, which was more than enough power to supply the original feeder load of approximately 2.054 MW. The simulations at each fault location consisted of having no DG in the system to see how the relay would react originally, having a minimal amount of DG set to supply approximately 100 kW each for a total of about 0.3 MW, and having a maximum amount of DG set to supply about 500 kW each for a total of about 1.5 MW. With the addition of the DG amounts, the amount of power supplied by the source decreased to about 1.708 MW and 0.748 MW for the minimal and maximum DG amounts respectively. The amount of fault resistance was chosen to be zero to make them bolted faults, which are the most severe type and cause protection devices to react faster. In addition, the fault type was chosen to be a single-line-to-ground fault as it is the most common fault type.

2.1. Distance Protection

As for the relay to be used in the system, it was chosen to be a distance or impedance relay with mho-based characteristics, mainly due to how it was a common block in PSCAD and could easily be implemented by taking the source current and voltage. The relay worked by taking the
ratio of current and voltage magnitudes (V/I) to solve for an impedance (Z) value [4]. That value was then compared to a pre-determined protection zone set by the real (R) and imaginary (jX) parts of the impedance such as seen in figure 2.

![Impedance Relay Diagram](image)

Figure 2. Mho-Based Characteristics of the Impedance Relay

Under normal operating conditions the measuring impedance, $Z_m$, will be the same as the load impedance, $Z_L$, but as the fault occurs, the ratio of voltage to current at the source or the measuring impedance begins to change and if that value crosses into the protection zone, $Z_{set}$, or in other words if $Z_m$ becomes less than $Z_{set}$ then the relay will trip the breaker [4]. Likewise, if $Z_m$ happens to never become less than $Z_{set}$ then the fault will not be considered in the protection zone and the breaker will not trip [4]. For this particular project, only one protection zone was used, but it is possible for many different zones to be on one relay.
For each fault location, three different simulations were done to collect the system data, which consisted of a no DG case, a low DG case, and a high DG case. The results were recorded by using the output channel overlay graphs in PSCAD and then the specific data points for each time step could then be placed into a spreadsheet type format to more easily read the values due to how close the samples were to each other. The general set-up of each simulation was set to have a 250 us step time and run for 20 seconds (s). The system was allowed to become stable before the DG’s were attached by closing their breakers which took about 3 s and then waited for the system and DG to stabilize again before the fault was applied at 15 s and told to last for 1 s. Doing the simulations this way allowed the system to be at a stable operating point before any major change was done to more accurately see that changes effect.

3.1. Relay Trip Time

As stated previously, the first goal of this project was to see how the inclusion of distributed generation on a distribution feeder would change the sensitivity of its protection relay. The three different fault locations used can be seen in figure 1 and again they were chosen to be near the source and start of the feeder, almost equally spaced between the DG’s and near the middle of the feeder, and close to a DG and near the end of the feeder.
3.1.1. Fault Location #1

Starting with fault location #1, figure 3 shows the trip time results for the three different total system DG amounts of 0 MW, 0.3 MW, and 1.5 MW and the time the fault started was also included as a reference point.

When the trip logic goes to 1 that was when the relay closed the breaker, and though it may be a bit difficult to see due to how close the sample time was, the relay tripped in 0.00325 s, 0.00425 s, and 0.00425 s after the fault started, where those are no DG, minimal DG, and maximum DG respectively. Due to its close proximity to the source, fault #1 had very fast trip times for all three cases. Both of the added DG amounts ended up having the same trip time, but that was only 0.001 s slower than the original system. Therefore, it would appear that adding DG had some, but very little impact on the relay sensitivity for this particular location.
3.1.2. Fault Location #2

Next, moving to fault location #2, the trip time results for the three different total system DG amounts as well as the fault start reference can be seen in figure 4.

![Figure 4. Breaker Trip Times for Fault Location #2](image)

Again, when the trip logic goes to 1 that was when the relay closed the breaker and the relay tripped for the no DG or original system case in 0.018 s after the fault started. Due to being near the middle of the feeder and having a larger resistance between it and the relay, fault #2 had a slower trip time than that of fault #1 by about 0.015 s. However, even when the fault ran for the full 1 s and was even tried for a full 5 s, neither of the DG added cases ever tripped the relay. Thus, it would appear that adding either DG amount to the feeder caused the relay to become desensitized for a fault near the middle of the feeder at location #2 and no longer functioned properly confirming DG’s possible negative impact on system protection.
3.1.3. Fault Location #3

Finally, for fault location #3, the trip time results for the three different total system DG amounts as well as the fault start reference can be seen in figure 5.

Once again, when the trip logic goes to 1 that was when the relay closed the breaker and the relay tripped for the no DG or original system case in 0.019 s after the fault started. Due to being near the end of the feeder and having an even larger resistance between it and the relay, fault #3 had a slower trip time than that of fault #1 and fault #2 by about 0.016 s and 0.001 s respectively. As was seen for fault #2, even when the fault ran for the full 1 s and was even tried for a full 5 s, neither of the DG added cases ever tripped the relay. Thus, it would appear that adding either DG amount to the feeder caused the relay to become de-sensitized for a fault near the end of the feeder at location #3 and no longer functioned properly. This result reinforces the concern that connecting DG to a distribution feeder tends to desensitize the protection relays under a fault condition especially at the end of its protection zone [7].
3.2. Impedance Relay Action

As previously stated, the protection relay used was a distance or impedance relay that was based on the ratio of voltage and current. For these tests, the relay was on the circuit breaker at the source or substation so it was monitoring that voltage and current. The zone of protection was set to be a relatively small amount near zero. Thus, if the source ratio entered the protection zone the relay would trip. Since not all of the simulation cases tripped, fault #3 was a good example to show how the relay operated. Figure 6 shows how the source currents reacted around the fault and just to note, the displayed current was the RMS value as it gave a single magnitude to more easily see the plots.

As can be seen in figure 6, all the RMS source currents increased when the fault occurred at 15 s, which was expected. The no DG case RMS current began to fall off and rapidly decrease once the breaker tripped and the source was disconnected causing the system to collapse, but the other RMS currents stabilized and stayed about the same as the protection breaker continued to stay
closed. To complete the impedance relay analysis, the source voltage also needed to be used to find the ratio between it and the current. Figure 7 then shows how the RMS source voltages reacted around the fault.

![Figure 7. RMS Source Voltages for Fault Location #3](image)

From figure 7, it can be seen that not long after the fault started at 15 s, the RMS voltage for the no DG case began to rapidly decrease which caused the voltage/current ratio to approach zero and trip the breaker as was seen in figure 5. This same event occurred for all the other fault tests done for location #1 and the no DG case for location #2, which is why they tripped. However, for the added DG cases on fault #2 and fault #3, their RMS source voltages, which were essentially the same, barely moved which caused the voltage/current ratio to not enter the zone of protection and caused the relay to never react to the fault.

### 3.3. System Current Changes

The second goal of this project was to see how the inclusion of distributed generation on a distribution feeder would change the fault and source currents in the system, and also how much
current the DGs could supply to the fault. The same three fault locations, near the source and the start of the feeder, almost equally spaced from the DG’s and near the middle of the feeder, close to a DG and near the end of the feeder, and DG amount setups, 0 MW, 0.3 MW, and 1.5 MW were used again to calculate the currents. The maximum RMS currents caused by the faults were used to check the DG impact since that would be the most severe amounts to the system, and also because they could be found for each of the simulations even for the cases where the relay did not trip as the maximum value was near the start of the fault in every case.

3.3.1. Fault Location #1

Starting with fault location #1, figure 8 shows the results for the source, fault, and total DG supplied maximum RMS current amounts for the three different DG amounts.

![Figure 8. Maximum RMS Current Amounts for Fault #1](image)

As can be seen in figure 8, the RMS currents do not seem to change all that much with the inclusion of DG due to how large the maximum amount of fault current was, almost 7 kA, and also because this fault was right next to the source and the farthest away from the DG’s. With no
DG attached, the fault and source RMS currents were nearly the same which was expected, but when the DG was added, the maximum source RMS current initially increased, possibly due to how the simulation was setup and the use of synchronous generators as DG that were not properly voltage regulated, but the source increased less, about 0.017 kA, compared to the fault current increase of about 0.088 kA. That extra increase was the result of the added current supplied by the DG. This simulations large amount of fault current was caused by the fault being next to the source, and that was also the reason that the source provided almost the entire fault current. However, as the amount of DG was increased from 0.3 MW to 1.5 MW, it did increase the amount of RMS current it supplied to the fault, about 0.068 kA, and also lowered the amount of RMS current supplied by the source by about 0.027 kA. Thus, it would appear that adding DG to the system could increase the severity of the fault current, but at the same time also lower the source current, which could cause radial protection looking at the amount of fault current there to lose some sensitivity. This appears to confirm the issue that DG can increase or decrease the amount of current that the relay would see [3].

3.3.2. Fault Location #2

Next, moving to fault location #2, the results for the source, fault, and total DG supplied maximum RMS current amounts for the three different DG amounts can be seen in figure 9.
As shown in figure 9, having currents that are closer in value makes it much easier to see the differences that DG can cause. With no DG attached, the fault and source RMS currents were nearly the same which was expected, but when the DG was added the maximum RMS source current initially increased, again possibly due to how the simulation was setup and the use of synchronous generators as DG that were not properly voltage regulated, but the source increased much less, only about 0.053 kA, compared to the fault current increase of about 0.178 kA. That extra increase was the result of the added current supplied by the DG. Once the DG amount was increased from 0.3 MW to 1.5 MW, the source RMS current then decreased by about 0.052 kA to be almost below the no DG case, where as the fault RMS current and its DG contribution continued to increase by about another 0.159 kA. Therefore just as with fault location #1, it would appear that adding DG to the system can significantly increase the severity of the fault current, but at the same time also lower the source current which could cause radial protection looking at the amount of fault current there to lose some sensitivity and confirm the problem of relay desensitization.
3.3.3. Fault Location #3

Finally, for fault location #3, the results for the source, fault, and total DG supplied maximum RMS current amounts for the three different DG amounts can be seen in figure 10.

![Figure 10. Maximum RMS Current Amounts for Fault #3](image)

As can be seen in figure 10, with no DG attached, the fault and source RMS currents were nearly the same which was expected, but when the DG was added the maximum RMS source current initially increased, once again possibly due to how the simulation was setup and the use of synchronous generators as DG that were not properly voltage regulated, but the source increased much less, only about 0.052 kA, compared to the fault RMS current increase of about 0.172 kA. That extra increase was the result of the added RMS current supplied by the DG of about 0.195 kA. Once the DG amount was increased from 0.3 MW to 1.5 MW, the source RMS current then decreased by about 0.051 kA to be almost the same as the original no DG case amount whereas the fault RMS current continued to increase by about 0.161 kA. At the same time, the current contribution from the DG increased by 0.223 kA, which was an even larger increase than the fault
current, and their amounts almost became the same value meaning that the DG was then supplying most of the fault current for the maximum DG case. As a result, just as with fault location #1 and fault location #2, it would appear that adding DG to the system can greatly increase the severity of the fault current and even supply much of it themselves, but at the same time also lower the source current. This could cause radial protection looking at the amount of fault current there to lose some sensitivity and again confirm the problem of relay desensitization.

3.4. Individual Generator Fault Currents

The amount of current that each DG contributed to a fault seemed to be dependent on its proximity to the fault. This was expected due to the idea that $I^2t$, where $I$ is the RMS current and $t$ is the time, effects are most severe in close proximity of added DG [7]. The theory was also backed up by looking at the original feeder case without any DG that showed when the fault moved away from the source, the source current decreased due to more resistance between the two. Figure 11 shows the general trend of the RMS fault current contributions from each of the distributed generators.

![Figure 11. RMS Fault Current Generator Contribution of Minimal DG (0.3 MW)](image)
As can be seen in figure 11, the DGs that were closest to the fault location provided the most current which is why for fault #3, the fault nearest to a DG, that particular DG, which was #2, contributed the majority of current where the other two provided only about half as much combined. Looking at fault #2, where the fault was placed at a nearly equal distance from the three DG’s, it can be seen that of the three locations it had the most balanced current contributions to the fault, but due to the fact that DG #2 and DG #3 contributed more than DG #1 suggests that there was a smaller resistance between them and the fault. For fault #1, only the first generator contributed much current to it due to being around the middle of the feeder, where as the other two generators being close to the end of the feeder, contributed almost nothing. Only the 0.3 MW case is shown due to how the 1.5 MW DG case gave the same ratios, just in different magnitudes as the amount of DG was increased.
CHAPTER 4

CONCLUSION

This paper first discussed some of the impacts that distributed generation could have on the radial protection of a distribution feeder and then simulations were conducted to attempt to confirm these suspicions. The changes in the relay sensitivity were explored using different DG amounts and fault locations throughout the feeder. These changes included looking at the time it took for the relay to detect the fault and trip the breaker for multiple simulations, which seemed to show that DG could cause the relay to react slower than before or not at all, as well as a more in-depth look at why the relay failed to react for fault location #3.

The paper also looked at how the added DG would alter the currents in the system by looking at the amount they could supply. The results showed that as more DG was added, the fault current and the DG current contributions to it increased, but the source current did not change very much. In addition, a closer look at the breakdown of how much each DG contributed to each fault was gone over to show how the fault proximity changed the supplied current amounts.

In reality, this paper’s simulations were based on an improbable set of conditions as the distributed generation used did not have any protection schemes themselves which they generally do as declared by the IEEE STD 1547 which says that the grounding scheme of the DG interconnection shall not disrupt the coordination of the ground fault protection on the Area EPS [1]. In other words, in order for a DG to be added to a system, it must first have its own set of protections to prevent it from changing any other protections previously on the system. However, it is possible for DG protections to fail or be improperly configured and this report was mainly focused on exploring the theoretical aspect to how DG’s could potentially affect an existing feeder system. Still, this paper is a good example to why this statement is in place as it proved
that DG has the potential to greatly alter system protections and it shows how important it is that these DG protections are correctly implemented.

Further investigation on this project/subject would likely involve adding more protection schemes around the feeder, especially on the DG’s, in order to find potential solutions to be able to use the added DG’s, but also keep the system protected. A good idea would also be to make sure that each DG as well as the entire system has proper voltage regulation. As the use of distributed generation continues to increase, more research must be done to ensure it is safely implemented to existing systems as any mistakes could cause potential dangers to both the system itself and those depending on it.
REFERENCES


