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Governor

FAULT LOCATION TECHNIQUES FOR DISTRIBUTION FEEDERS CONTAINING DISTRIBUTED GENERATION

INDEPENDENT ASSESSMENT REPORT

Prepared For:
California Energy Commission
Public Interest Energy Research Program
Energy Innovations Small Grants Program

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PREFACE

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

PIER funding efforts are focused on the following research, development, and demonstration (RD&D) program areas:

- Building End-Use Energy Efficiency
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Environmentally Preferred Advanced Generation
- Energy-Related Environmental Research
- Energy Systems Integration
- Transportation
- Energy Innovations Small Grant Program

The PIER Program, managed by the California Energy Commission (Energy Commission), annually awards up to $62 million, of which 5 percent is allocated to the Energy Innovation Small Grant (EISG) Program. The EISG Program is administered by the San Diego State University Foundation through the California State University, which is under contract with the California Energy Commission.

The EISG Program conducts up to six solicitations a year and awards grants for promising proof-of-concept energy research.

The EISG Program Administrator prepares an Independent Assessment Report (IAR) on all completed grant projects. The IAR provides a concise summary and independent assessment of the grant project to provide the California Energy Commission and the general public with information that would assist in making subsequent funding decisions. The IAR is organized into the following sections:

- Introduction
- Project Objectives
- Project Outcomes (relative to objectives)
- Conclusions
- Recommendations
- Benefits to California
- Overall Technology Assessment
- Appendices
    - Appendix A: Final Report (under separate cover)

- Appendix B: Awardee Rebuttal to Independent Assessment (awardee option)

For more information on the EISG Program or to download a copy of the IAR, please visit the EISG program page on the California Energy Commission's website at: http://www.energy.ca.gov/research/innovations or contact the EISG Program Administrator at (619) 594-1049, or e-mail at: eisgp@energy.state.ca.us.

For more information on the overall PIER Program, please visit the California Energy Commission's website at http://www.energy.ca.gov/research/index.html.

Abstract

The accurate location of faults on electricity distribution systems can greatly expedite the recovery of those systems and reduce outage time. Methods of fault location have been developed for transmission and distribution systems. Many of these methods, however, do not account for distributed generation on the system. Distributed generation is expected to be a realistic option for utilities and consumers in a developing competitive electric market. Therefore, there is a need to modify current methods of fault location to account for distributed generation. This report presents a modified three-phase fault location method. The modifications allow for the accurate location of faults on realistic distribution systems that have distributed generation. The method also accounts for unbalanced loads and unequal mutual coupling.

This research considers realistic waveforms during fault conditions. These waveforms consist of main signal (60 Hz waveform) plus the fault-induced transients. These transients consist mainly of high frequency noise with a wide spectrum and dc offset. The approach starts by a digital processing technique that takes the distorted samples of current and voltage data and computes the phasor quantities of the three-phase voltage and current data.

The report begins with an analysis of two existing methods of fault location, the apparent impedance method and the three-phase method. Each was evaluated based on its accuracy in locating faults on systems that have distributed generation. The modified three-phase method was developed and tested on the same system to show the improved accuracy of this method. The report shows the results of this method applied to a real system for single-line-to-ground, double-line-to-ground, line-to-line, and three-phase faults.

The results presented in this report demonstrate the inadequacy of existing methods to account for distributed generation (DG). Also the modified three-phase method results that are shown are accurate estimations of fault location by accounting for DG.

Keywords: fault locations, distribution generation, modified three-phase fault location method frequency.

Introduction

An electric power distribution system typically has many miles of overhead conductors and underground cables. These conductors and cables suffer faults[1] for various reasons. The speed with which these faults can be located, evaluated, and repaired minimizes the customer down time and improves system reliability. The principal investigator indicated that fault-location techniques have been developed that use circuit data measured at the substation to estimate the fault location[2]. These methods have been accurate for radial distribution systems; that model assumes that power flows from only one source, the substation, to the various loads (customers). The fault-current contribution from the substation allows the power company to estimate the location of the fault. The addition of distributed generation at various customer sites changes the distribution circuit of the power flow. A customer with distributed generation could receive power from various sources. Fault currents would now have components contributed by both the substation and the distributed generation units. These additional fault-current contributions must be taken into account to properly estimate the fault location. The principal investigator identified the need to modify the existing methods to include the contributions of both the fault current and the distributed generation unit normal current for accurate estimates of fault locations.

The speed with which a cable fault can be located and repaired directly affects the reliability of the distribution grid. In California, California Public Utilities Commission Decision 96-09-045 imposed electrical system reliability recording, calculation, and reporting requirements on Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric, Sierra Pacific Power, and PacifiCorp. There are three indices: System Average Interruption Duration Index in minutes of sustained outage per customer per year; System Average Interruption Frequency Index, number of sustained outages per customer per year; and Momentary Average Interruption Frequency Index, number of momentary outages per customer per year. System Average Interruption Duration Index and System Average Interruption Frequency Index include sustained outages, which are defined as outages lasting five minutes or more. Momentary Average Interruption Frequency Index comprises momentary outages, which are defined as outages lasting less than five minutes. System statistics are computed as follows: 1) including transmission, substation, and distribution outages, and 2) excluding planned outages.

Table 1 and Table 2 below show system indices for California[3]. Note that the average distribution customer will experience few outages (less than two) but long ones (over 120 minutes) due to a malfunction in the distribution system.

[1] A fault typically is defined as an incident that causes a very high amount of current flow to the point where protective devices take action. Common causes are: equipment malfunction, tree contact, animal contact, or excavation contact. Protective devices typically are fuses, circuit breakers, and recloser switches.

[2] The two methods mentioned by the principal investigator are the “apparent impedance” and the “three phase method.” These methods estimate the fault location by using measured/recorded fault data (voltage/current). A detailed explanation of these methods appears in Appendix I and II of the EISG Final Report.

[3] Table 2 is from CPUC Electrical System Reliability Reports, 03_01_04 CPUC2003-Rpt Final.doc.

Table 1: System Indices, 1994-2003
Includes Transmission, Distribution and Generation related outages

	Major Events Included			Major Events Excluded		
YEAR	**SAIDI**	**SAIFI**	**MAIFI**	**SAIDI**	**SAIFI**	**MAIFI**
1994	160.3	1.721	1.952	155.4	1.540	1.872
1995	600.2	2.616	2.216	170.2	1.537	1.649
1996	347.0	2.462	4.855	178.1	1.709	4.654
1997	171.3	1.700	4.430	161.8	1.639	4.335
1998	317.0	2.130	3.835	180.0	1.659	3.407
1999	157.2	1.481	2.427	156.7	1.477	2.420
2000	168.4	1.413	2.282	167.9	1.410	2.281
2001	249.1	1.560	2.256	211.8	1.439	2.120
2002	381.8	1.672	2.578	139.7	1.114	2.000
2003	198.9	1.328	1.806	193.0	1.308	1.802

Table 2: Distribution System Indices, 1994-2003
Excludes outages related to transmission and generation

	Major Events Included		Major Events Excluded	
YEAR	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
1994	139.2	1.400	139.2	1.400
1995	536.6	2.393	150.3	1.384
1996	198.4	1.685	167.1	1.632
1997	157.3	1.562	148.4	1.507
1998	245.0	1.812	157.3	1.493
1999	145.1	1.324	144.8	1.321
2000	152.3	1.293	151.8	1.290
2001	228.6	1.430	192.5	1.316
2002	341.2	1.533	129.7	1.030
2003	179.6	1.209	173.8	1.190

Rapid, accurate location of cable faults can reduce the SAIDI index and produce greater grid reliability.

The principal investigator proposed to develop a modified method of fault location for power-distribution lines that include distributed generation power sources. It would use the recorded substation and DG data before and during the fault and be capable of estimating the fault location within 1 percent error and within 100 milliseconds of a fault occurrence. This would greatly minimize the time required to locate the exact location of a fault and restore the distribution circuit.

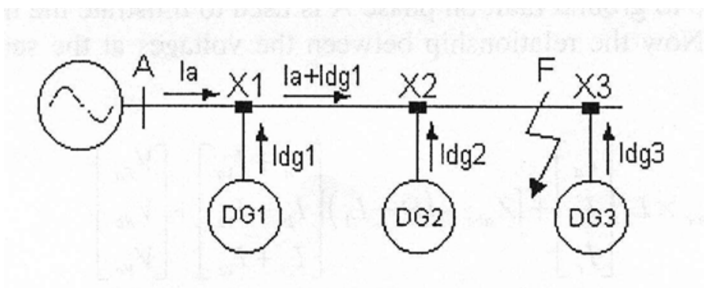

Figure 1: Distribution Feeder with distributed generators showing a fault (F) and the current contributions.

Objectives

This project was to demonstrate the feasibility of developing a modified method of fault location to account for the presence of distributed generation in a distribution system. The researcher established the following project objectives:

1. Develop a modified method of fault location for power distribution lines incorporating distributed generation power sources.
2. Demonstrate that the proposed method is capable of locating faults on distribution lines containing distributed generation within 1 percent error[4].
3. Demonstrate that the proposed method is capable of locating faults on distribution lines containing distributed generation within 100 milliseconds of a fault occurrence.

Outcomes

To establish a baseline for the new method the researcher evaluated the existing "apparent-impedance method" for fault-location estimates on a modeled 10-mile, distributed-generation source. The distribution system was modeled using the Alternate Transients Program[5]. The evaluation results show unacceptable errors in fault location. The error range was from 9 yards to 48 miles.

[4] The principal investigator did not specifically indicate how the 1 percent was defined. It is inferred to mean 1 percent of total conductor/cable length in the feeder being evaluated.
[5] Alternate Transients Program is a universal program system for digital simulation of transient phenomena of electromagnetic as well as electromechanical nature. See http://www.emtp.org for more details.

The researcher also evaluated the existing "three-phase method" for fault-location estimates on a modeled 10-mile, distributed generation source. The distribution system was modeled with Alternate Transients Program and MATLAB[6]. That error range was 60 yards to 63 miles.

1. The researcher demonstrated the developed "modified three-phase method" fault location algorithm on the hypothetical 10-mile distribution system.
2. The researcher simulated single-line-to-ground faults using PSCAC/EMTDC [7]and located the faults with an error range of less than 15 yards in 10 miles. This is considerably less than 1 percent.
3. The applicant obtained characteristic data from a "real-world" distribution system with one substation and two distributed generators. Using the same PSCAD/EMTDC software to simulate faults produced the following results: single-line-to-ground faults had an error range of 0 to 195 yards; double-line-to-ground faults had an error range of 1 to 190 yards; line-to-line faults had an error range of 0 to 405 yard and triple-line faults had an error range of 0 to 360 yards.

Conclusions

The principal investigator in this project developed a modified three-phase method to locate faults in a distribution system that included distributed generation. The data indicate that the developed method is fast and accurate, but it needs more real-world testing and refinement for more complicated configurations.

The principal investigator demonstrated that, based on simulation results, the existing "apparent-impedance method" is not suitable for accurately estimating fault locations on a distribution system with distributed generation.

Similarly, the existing "three-phase method" is not suitable for estimating fault locations on a distribution system with distributed generation.

1. The applicant developed a modified "three-phase method" for estimating fault-locations on a distribution system with distributed generation.
2. The modified "three-phase method" was shown to be accurate in predicting fault locations on a simulated distribution system with distributed generation. The error range was 0 to 15 yards.
3. The researcher easily met the objective of locating faults on generation lines within 100 milliseconds.

The researcher indicated that the developed method may need further research for underground cables. It is not clear why the applicant made this statement in the conclusion of the executive summary without additional details in the body of the report.

[6] MATLAB is a software engineering toolbox for mathematical modeling and other uses. See http://www.mathworks.com for more details.
[7] PSCAD/EMTC stand for Power Systems Computer Aided Design/ElectroMagnetic Transients for DC. It represents a family of power system simulation products.

Recommendations

The modified “three-phase method” for estimating fault locations should be a valued addition to a grid that includes both distributed generation and a high degree of real-time measurement data available for fault analysis. In California, the typical distribution grid does not yet have a high degree of real-time measuring capability. This situation may change as distributed generation becomes more prevalent. The principal investigator indicated that the method should be tested in the real world and in more complex distribution-grid configurations.

After taking into consideration (a) research findings in the grant project, (b) overall development status, and (c) relevance of the technology to California and the PIER program, the program administrator has determined that the proposed technology should be considered for subsequent funding within the PIER program.

Receiving subsequent funding ultimately depends upon (a) availability of funds, (b) submission of a proposal in response to an invitation or solicitation, and (c) successful evaluation of the proposal.

Benefits to California

Public benefits derived from PIER research and development are assessed within the following context:

- Reduced environmental impacts of the California electricity supply, transmission or distribution system.
- Increased public safety of the California electricity system.
- Increased reliability of the California electricity system.
- Increased affordability of electricity in California.

The primary potential benefit to the ratepayer of this research would be increased reliability of the California electricity system. The higher grid reliability should result in shorter outages and overall improved customer satisfaction. The developed technique is only useful in areas of the grid where multiple power sources are feeding a circuit and where real-time data is available. In an interview conducted by the program administrator, a Southern California Edison substation engineer commented on the current distribution-system troubleshooting procedures for faulted cables. The basic approach is to allow the existing relays, re-closers, and fuses to lockout the affected section. Alarms are noted at the operational center. After evaluation, a crew is dispatched to investigate and correct the outage. Very few stations are “real-time ready” for telemetry. There are no coordinated means of obtaining real-time data from the qualified generation facilities. In this scenario, the new method of fault isolation may not have much value until more instrumentation and telemetry are installed in California’s grid.

Additionally, for any DG site that is capable of exporting power to the grid, the utility requires a fault-current contribution value. This value is then used to update the protection circuitry coordination for that portion of the distribution grid.

A possible application would be to monitor the sub-transmission circuits, or those that link and feed substations. These circuits tend to be monitored in real time, and the necessary data for fault location could be fed into the technique developed by the principal investigator.

Overall Technology Transition Assessment

As the basis for this assessment, the program administrator reviewed the researcher's overall development effort, which includes all activities related to a coordinated development effort, not just the work performed with EISG grant funds.

Marketing/Connection to the Market

The developed modification can easily be integrated into existing software, simulation, embedded controls, and existing power distribution SCADA[8] systems.

Engineering/Technical

This project demonstrated the limitation of existing fault-location methods (apparent impedance and three-phase) and the ability of the modified three-phase method to accurately predict fault locations on simulated systems. The next step is to test it on actual systems in real time.

- The modified method could be tested in California utility distribution circuits that have SCADA and distributed-generation sites with available real-time telemetry.
- The method could be evaluated with respect to existing fault-location protocols. This may prove to be a valuable addition to procedures that locate faults and restore circuits.

Legal/Contractual

The applicant stated that the project does not contain proprietary information, and he authorized unrestricted distribution of his findings.

Environmental, Safety, Risk Assessments/ Quality Plans

Formal quality planning, environmental, safety and risk assessments are not recommended at this stage. Any utility implementing the developed technique must evaluate the risks and safety effects of using this technique.

Production Readiness/Commercialization

The principal investigator indicated no intent to continue effort towards commercialization. The technique is readily adaptable to existing software of microprocessor-controlled equipment.

Appendix A: Final Report (under separate cover)

Appendix B: Awardee Rebuttal to Independent Assessment (none submitted)

[8] SCADA stand for Supervisory and Control and Data Acquisition. This is process control system that allows monitoring and control from a central location.

Attachment A – Grantee Report

FAULT LOCATION TECHNIQUES FOR DISTRIBUTION FEEDERS CONTAINING DISTRIBUTED GENERATION

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Legal Notice

Inquires related to this final report should be directed to the Awardee (see contact information on cover page) or the EISG Program Administrator at (619) 594-1049 or email eisgp@energy.state.ca.us.

Table of Contents

Abstract

The accurate location of faults on distribution systems can greatly expedite the recovery of those systems and reduce outage time. Methods of fault location have been developed for transmission and distribution systems. Many of these methods, however, do not account for distributed generation on the system. Distributed generation is expected to be a realistic option for utilities and consumers in a developing competitive electric market. Therefore, there is a need to modify current methods of fault location to account for distributed generation. This report presents a modified three phase fault location method. The modifications allow for the accurate location of faults on realistic distribution systems that have distributed generation. The method also accounts for unbalanced loads and unequal mutual coupling.

This research considers realistic waveforms during fault conditions. These waveforms consist of the main signal (60 Hz waveform) plus the fault-induced transients. These transients consist mainly of high frequency noise with a wide frequency spectrum and dc offset. The approach starts by a digital processing technique that takes the distorted samples of current and voltage data and computes the phasor quantities of the three phase voltage and current data.

The report begins with an analysis of two existing methods of fault location, the apparent impedance method and the three phase method. Each was evaluated based on its accuracy in locating faults on systems that have distributed generation. The modified three phase method was developed and tested on the same system to show the improved accuracy of this method. The report shows the results of this method applied to a real system for single line to ground, double line to ground, line to line, and three phase faults.

The results presented in this report demonstrate the inadequacy of existing methods to account for distributed generation (DG). Also the modified three phase method results that are shown are accurate estimations of fault location by accounting for DG.

Executive Summary

Introduction

Today, distributed generation (DG) is becoming a realistic option for utilities and consumers. DG can greatly affect system protection and stability because they are downstream sources of power. Distribution systems experience thousands of faults per year. These can be caused by various reasons including severe weather, animals, and equipment malfunction. To expedite the recovery process, fault location techniques have been developed. These location methods use recorded fault data at the substation to estimate the fault location. The methods developed have been accurate for radial distribution systems, but with the growing presence of DG in distribution systems, there is a need to modify these methods. The goal of this project is to demonstrate the feasibility of developing a modified three phase fault location method in order to account for the presence of distributed generation and unbalanced loading conditions.

Project Objectives

1) Develop a modified fault location method for power distribution lines that include distributed generation power sources.
2) Demonstrate that the proposed method is capable of locating faults on distribution lines containing distributed generation within one percent error.
3) Demonstrate that the proposed method is capable of locating fault on distribution lines containing distributed generation within 100 milliseconds of a fault occurrence.

Project Outcomes

1) Using the apparent impedance method (Appendix I.) for estimation of the fault locations in the presence of DG resulted in unacceptable errors.

2) The three-phase method for fault location also resulted in high error due to the presence of DG.
3) A modified three-phase method that accounts for distributed generation was developed.
4) The modified three-phase method accurately identified fault locations on the test system with errors less than the errors of existing methods by a factor of ten. The maximum error was 15 yards but further research may be needed for underground cables. This is certainly very accurate for overhead distribution lines.
5) Detailed data of a real-world distribution system containing distributed generation was obtained.
6) The proposed three-phase method accurately identified fault locations for a real world distribution system for all types of faults with acceptable error for overhead lines. The errors were much smaller than existing methods errors.

Conclusions

1) The present apparent impedance and three phase methods are not appropriate methods for determining fault locations on distribution systems where distributed generation is present.
2) The three phase method can be modified to accurately account for the presence of distributed generation. The method needs two cycles of row samples of the three phase voltage and current waveforms. The data consist of one cycle of prefault data and one cycle during fault data. The algorithm typically takes 10 milliseconds to calculate the fault location. Thus, the total time taken from fault occurrence to the completion of fault location computation is about 30 m seconds.

3) The modified three phase method still has room for improvement. The accuracy of this method, in comparison with other existing methods, was still acceptable when the real world system data was used. However, further research may be needed for higher accuracy in underground cables.

Recommendations

1) The next step in testing the current modified three phase method is to acquire real fault data in order to ensure accuracy.
2) The modified three phase method has room for improvement and should be developed to account for more complicated configurations.

Public Benefits to California

The benefit to California ultimately is the swift recovery of faulted distribution systems that have distributed generation. The development of methods to locate faults is the first step toward this goal. The accurate location of faults gives control centers information that can greatly expedite the recovery of their systems by allowing them to make informed decisions on what can be safely restored. Also it allows repair crews to go straight to the damaged area without having to search miles of distribution line to locate the fault. With methods that accurately locate faults, California's power security will have made a step forward.

Introduction

Distribution systems are traditionally designed to deliver one directional power along radials fed from a substation, which could involve large areas of land and various configurations. Today, distributed generation (DG) is becoming a realistic option for utilities and consumers. DG can greatly affect system protection and stability because they are downstream sources. The potential benefits that DG can provide are improved reliability, and lower cost by providing power near or at loads. Protective devices can be redesigned to eliminate these problems that DG can cause and reap the benefits they can provide [1].

Distribution systems experience thousands of faults per year. These can be caused by various reasons including severe weather, animals, and equipment malfunction. Traditionally fault conditions, if permanent, were corrected by first locating where the fault occurred in order to send repair crews to repair damaged components. Locating the fault was determined by customer reporting of power outages. The dispatcher would use reports to estimate the location of the fault using network maps and would send a repair crew to patrol the area searching for the fault. This process can be long and does not guarantee a quick recovery of the system [3]. To expedite the recovery process, fault location techniques have been developed [1-14]. These location methods use recorded fault data at the substation to estimate the fault location. The methods that have been developed have been accurate for radial distribution systems, but with the growing presence of DG in distribution systems, there is a need to modify these methods. Past techniques have assumed that there is one directional power flow from the substation, but in a system where DG is present; there is the possibility of multidirectional power flow, especially in faulted conditions. [1]

The goal of this project is to demonstrate the feasibility of developing a modified fault location method in order to account for the presence of distributed generation. This report will discuss the development of this technique by first discussing the project objectives, approach and outcomes. Following this, conclusions on the results will be drawn and recommendations for future work will be made.

Project Objectives

- Develop a modified fault location method for power distribution lines that include distributed generation power sources.
- Demonstrate that the proposed method is capable of locating faults on distribution lines containing distributed generation with one percent error.
- Demonstrate that the proposed method is capable of locating fault on distribution lines containing distributed generation within 100 milliseconds of a fault occurrence.

Project Approach

Task 1: The main goal of this task was to determine the effect of distributed generation on calculating an accurate fault location using the apparent impedance method (Appendix I). A basic distribution system model as shown in Figure 1 was the test system. It had one distributed generator 5 miles from the substation and an equally distributed 10MVA load.

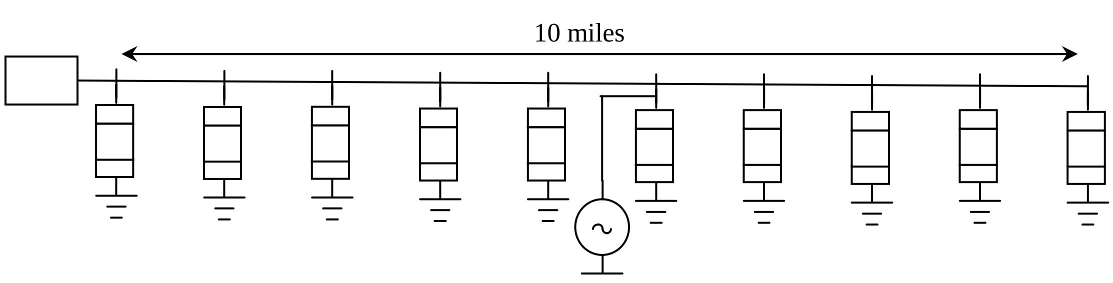

Figure 1: Basic distribution system for testing the apparent impedance method.

The test system was modeled in Alternate Transients Program (ATP) to acquire sampled voltage and current data during faulted conditions similar to what would be obtained from a digital fault recorder (DFR). Data for a single line to ground fault was generated at 20 different locations along the given 10 mile feeder. The apparent impedance method was then used to calculate the fault location in each case. Because the basic apparent impedance method does not account for loading in the system, a modified apparent impedance method was used to more accurately single out the effect of the DG in the system (Appendix II).

Task 2:

Task 2.1: Development of a modified three-phase component fault location algorithm.

The developed three-phase component modified fault location technique is able to account for many different configurations on distribution systems. Specifically it can account for single and multiple phase loads, unbalanced feeders, and multiple distributed generators.

Task 2.2: Using of three-phase fault analysis to obtain voltage and current data representative of data obtained from a digital fault locator.

To model a realistic system, a 10 mile feeder with 10MVA distributed load was chosen. Three distributed generators were also placed on the system. Modifications to the technique are made to account for the load current and the current contribution of distributed generators to acquire accurate results when locating a fault.

Task 2.3: Simulate faults along a feeder using EMTDC software to obtain voltage and current waveforms during fault conditions.

Testing of these modifications have been accomplished using Alternative Transient Program (ATP) and MATLAB. To start, a simple system with no DG and one load was used just to test the modified technique. The results for this test had less than one percent error. The simple system was then modified to include a normally distributed 10 MVA load across a 10 mile feeder. The load modification was used to estimate faults along the feeder.

Task 2.4: Develop the complete three-phase fault location algorithm.

The general steps of the three-phase fault location algorithm were completed. The algorithm is general enough to account for single or multiple distributed generators in a distributed feeder. Data at the distributed generators is assumed to be available and considered in the algorithm.

Task 3: Test of a three-phase fault location algorithm using simulation software.

The newest version (V4) of the PSCAD/EMTDC is being used to simulate distribution feeders with multiple distributed generators. The simulation includes different line section configuration; different fault types and locations. The simulation produces real time data of voltage and current waveforms at the substation from pre-fault to post-fault conditions. The samples of voltage and current waveforms are then applied to the fault location algorithm for testing.

Task 4: Obtain real work detailed data of actual distribution feeder with distributed generation.

An actual distribution feeder data was obtained. The feeder data includes feeder sections with actual configuration and loads. The feeder has unequal phase spacing and thus represent realistic unbalanced impedance matrix. Distributed generators are evenly distributed along the feeder. The system was simulated on PSCAD/EMTDC to obtain voltage and current waveforms at the substation due to all types of faults at all locations.

Task 5: Validate performance claims of the proposed scheme using real work distributed feeder data.

A real world distribution system is simulated on PSCAD/EMTDC to obtain real time data for all types of fault at all locations. The system represented unbalanced distribution system with multiple distributed generators. The test results on a real life feeder show an error ranges from 0 to 270 yards. The mean error is 58 yards with a standard deviation of 62 yards.

Project Outcomes

I. Using the apparent impedance method for estimation of the fault locations in the presence of DG resulted in unacceptable errors.

Figure 3 shows the results of testing the apparent impedance method. The error ranged from 9 yards to 48 miles. The mean error was 11 miles and the standard deviation was 15. The estimation in cases where the fault was in the first few miles may appear to be accurate from Figure 3, but in reality there is extremely high error in all fault locations due to the DG.

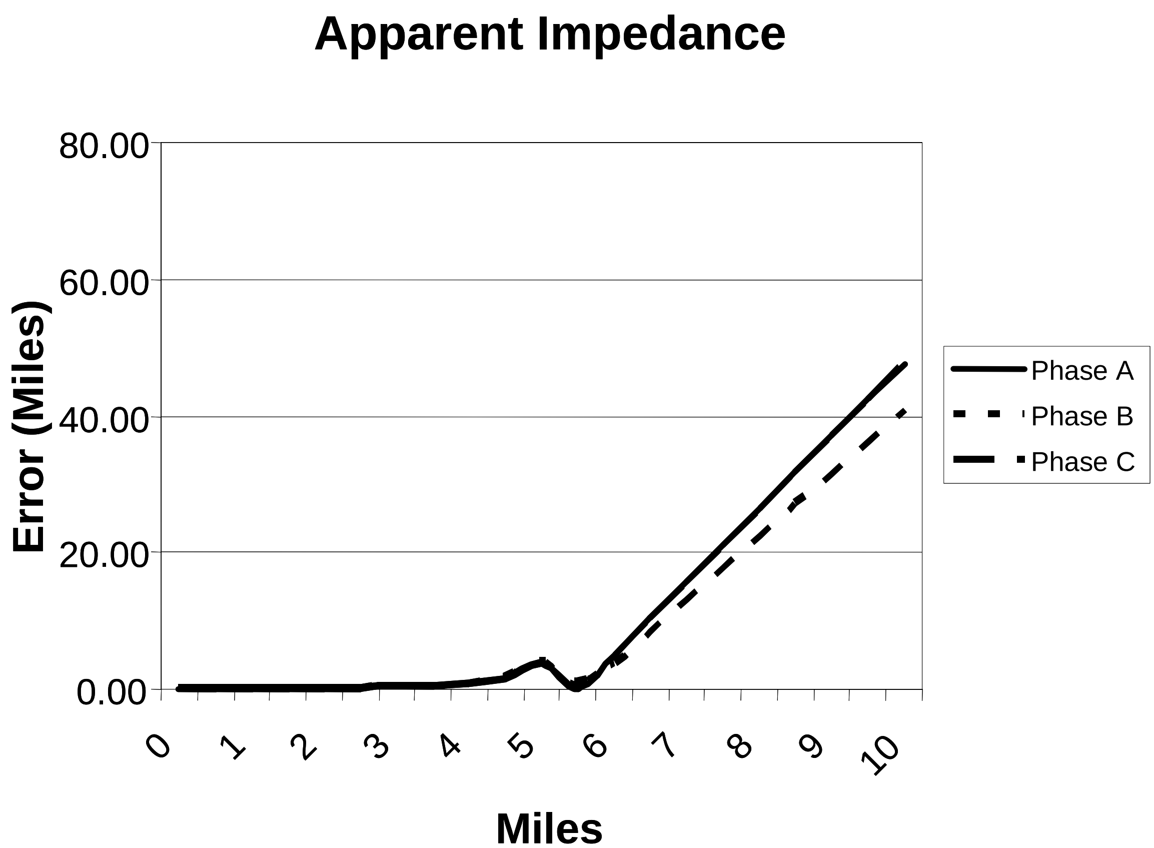

Figure 3: Errors in the apparent impedance method.

II. The three-phase method for fault location also resulted in high error due to the presence of DG.

The effects of distributed generation on the three-phase method were similar to that of the apparent impedance method as can be seen from Figure 4. The error ranged from 60 yards to 63 miles. The mean error was 15 miles and the standard deviation was 20.

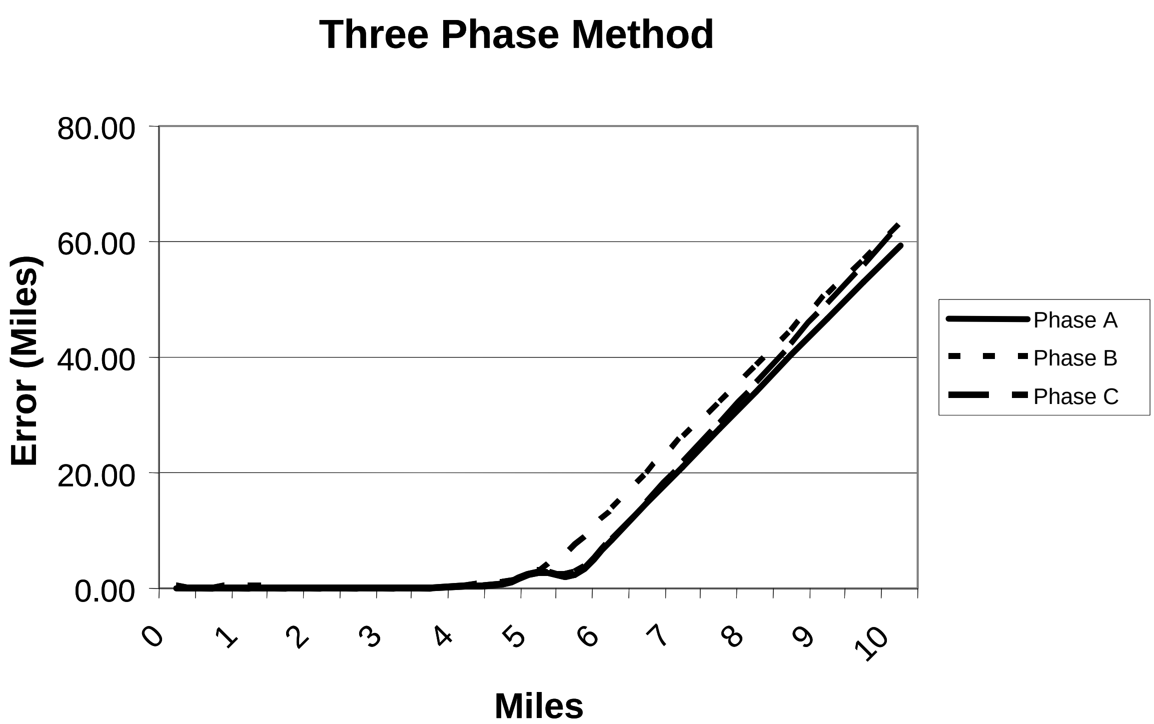

Figure 4: Errors in the fault location using a three-phase method.

III. A modified three-phase method that accounts for distributed generation was developed.

In the development of this method, it was realized that it was necessary to have fault data available at all DG that have the ability to put power back into the system. The modified method makes estimations of the fault location from the substation and the distributed generators on the system based on the availability of fault data at each location. This information allows the fault current to be more accurately estimated which is vital to accurate estimation of the fault location using the three-phase method.

IV. The modified three-phase method accurately identified single line to ground fault locations on the test system with errors less than 15 yards.

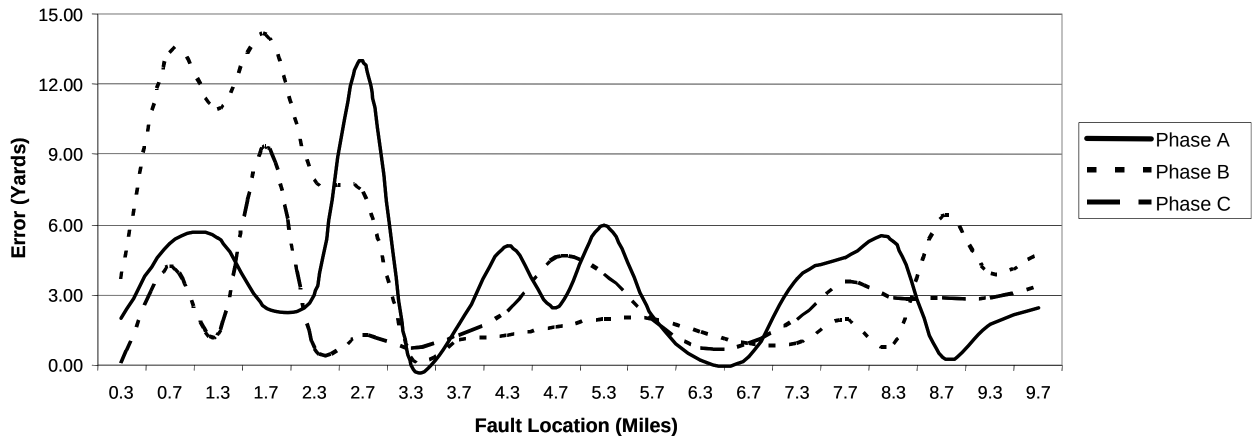

Figure 5: Errors in fault location using the modified three-phase method.

The error ranged from 0 yards to 14 yards. The mean error was 3 yards and the standard deviation was 3 yards.

V. Detailed data of a real-world distribution from a local utility system containing distributed generation was obtained. Data of the system is shown in Appendix V.

A typical distribution system containing two distributed generators was obtained from a local utility. Line parameters, line configurations, system loading data, generator impedance, and transformer parameters were all provided. A scaled one line diagram of the system is shown below. The fault resistance in all simulations was 1 ohm.

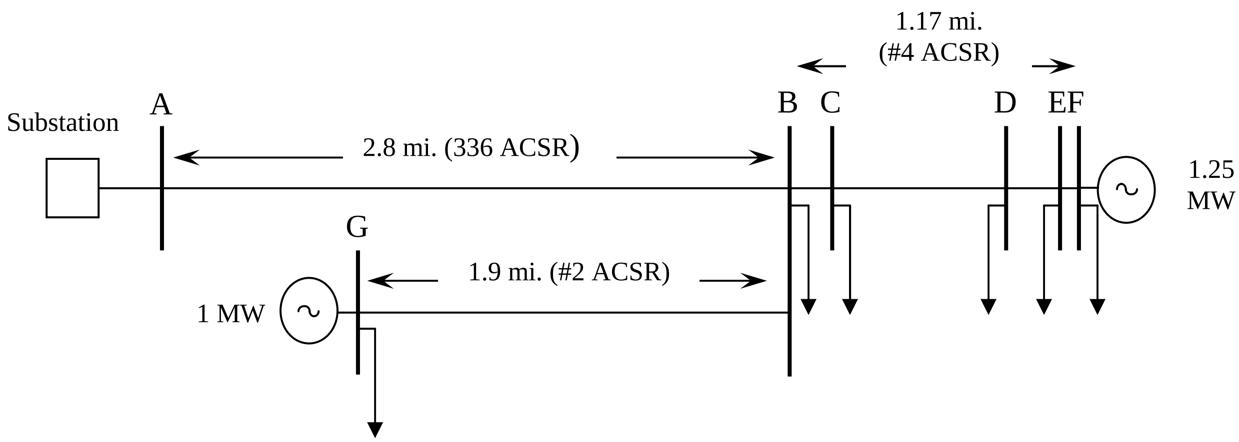

Figure 6: A one line diagram of actual 13.8 KV distributed system used.

VI. The proposed three-phase method accurately identified fault locations for a real world distribution system.

A. Single Line to Ground Faults

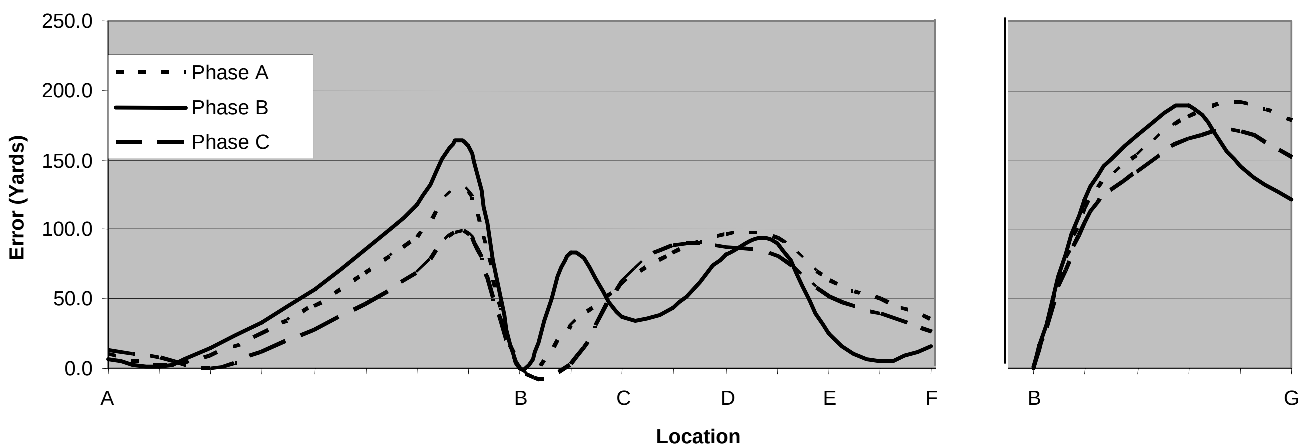

Figure 7: Errors in fault location for single line to ground faults in the system of Figure 6.

The error ranged from 0 yards to 195 yards. The mean error was 70 yards and the standard deviation was 58 yards.

B. Double Line to Ground Faults

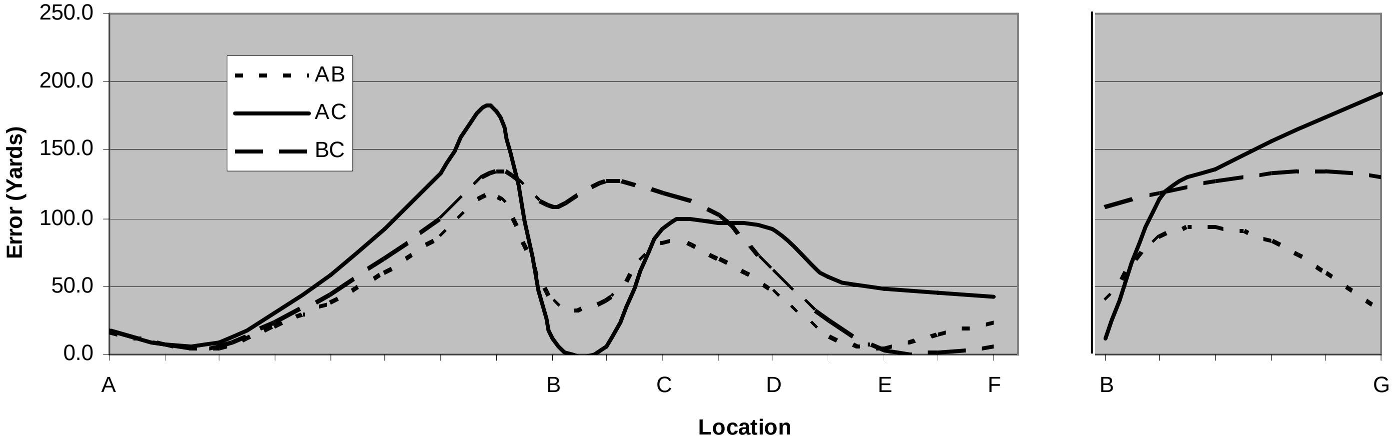

Figure 8: Errors in fault location for double line to ground faults in the system of Figure 6.

The error ranged from 1 yard to 190 yards. The mean error was 66 yards and the standard deviation was 55 yards.

C. Line to Line Faults

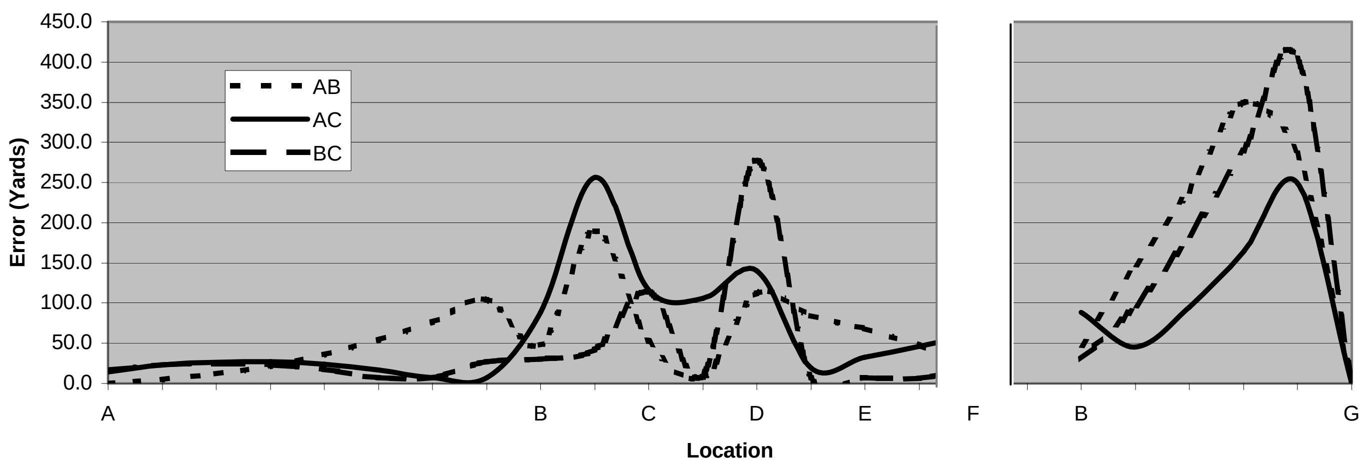

Figure 9: Errors in the fault location for a line to line fault in the system of Figure 6.

The error ranged from 0 yards to 405 yards. The mean error was 77 yards and the standard deviation was 93 yards.

D. Three Phase Faults

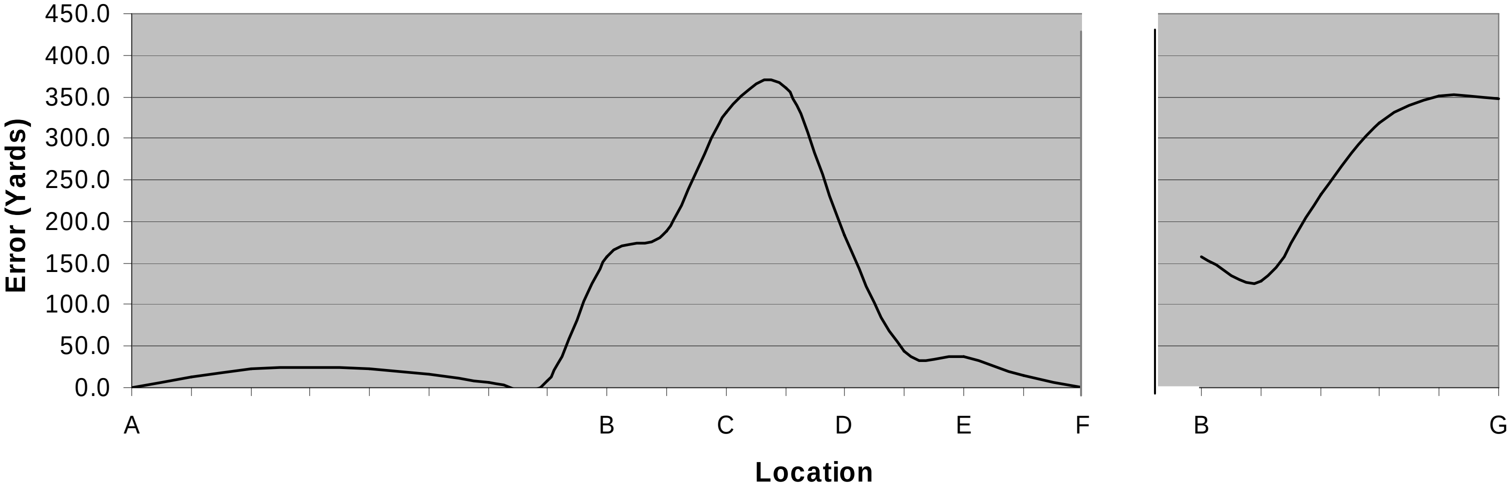

Figure 10: Errors due to a three-phase fault in the system of Figure 6.

The error ranged from 0 yards to 360 yards. The mean error was 128 yards and the standard deviation was 135 yards. It should be noted that for all these faults, noisy data was obtained from the electro magnetic transient program. The data included the 60 Hz and fault-induced transients (noise). A digital signal processing technique extracted the phasor quantities, identified the faulted phases and then calculated the fault location.

Conclusions

1) The present apparent impedance and three phase methods are not appropriate methods for determining fault locations on distribution systems where distributed generation is present. The possibility of fault current being supplied from other sources other than from the substation cause the assumptions made by previous methods invalid. These assumptions caused the demonstrated inaccuracies in both methods.

2) The three phase method can be modified to accurately account for the presence of distributed generation. The algorithm takes .01 seconds to locate the fault on a 1 GHz Windows based machine. This includes Discrete Fourier Transform (DFT) calculations.

3) The modified three phase method still has room for improvement. The accuracy of this method was still acceptable when the real world system data was used, but much more accurate when the test system was evaluated. These differences are due to the differences in the simulation software and the configuration of each system.

Recommendations

1) The next step in testing the current modified three phase method is to acquire real fault data in order to ensure accuracy.

2) The modified three phase method has room for improvement and should be developed to account for more complicated configurations. A common example is systems that have single phase laterals. It would also be necessary to include protection data into the method to improve accuracy.

3) The three phase method was modified in this research to account for distributed generation, but it would be beneficial to modify other current methods to determine the best approach to fault location on distribution systems.

Public Benefits to California

The benefit to California ultimately is the swift recovery of faulted distribution systems that have distributed generation. The development of methods to locate faults is the first step toward this goal. The accurate location of faults gives control centers information that can greatly expedite the recovery of their systems by allowing them to make informed decisions on what can be safely restored. Also it allows repair crews to go straight to the damaged area without having to search miles of distribution line to locate the fault. With methods that accurately locate faults, California's power security will have made a step forward.

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Appendix I

Apparent Impedance Fault Location Method

Apparent Impedance is the basis for many fault location methods. This method calculates an impedance that represents the total positive sequence impedance seen at the line terminal. The factors that contribute to the actual apparent impedance include line transposition, fault resistance, remote end-feed and prefault current. This method primarily uses sequence components and therefore does not account for unequal mutual coupling or unbalanced loading conditions. To demonstrate the principles of the apparent impedance method the fault location of a single line to ground fault on phase A of the basic system one line diagram shown in Figure I.1 will be developed.

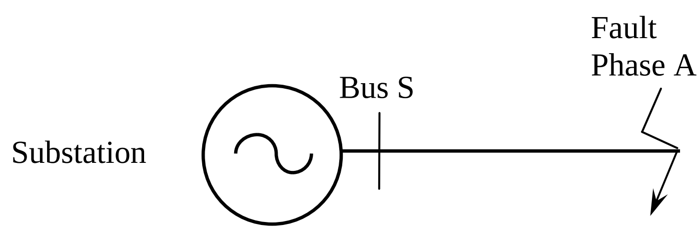


Figure I.1

Using sequence components the sequence voltages at bus S can be expressed as:

$$
\begin{aligned}
V_S^0 &= DI^0 Z^0 + V_F^0 \\
V_S^1 &= DI^1 Z^1 + V_F^1 \\
V_S^2 &= DI^2 Z^1 + V_F^2
\end{aligned}
\qquad (1)
$$

'Z' is the sequence impedance of the line in ohms per unit length and D is the distance to the fault. It is assumed that $Z^1 = Z^2$. The voltage at the fault for phase A can be determined using unbalanced fault analysis methods using sequence components where:

$$V_F^A = V_F^0 + V_F^1 + V_F^2 = 3I_F^0 R_F \quad (2)$$

The fault resistance R_F is another unknown quantity besides the fault location and has to be addressed.

The voltage and current on phase A at the substation can be expressed as:

$$V_S^A = V_S^0 + V_S^1 + V_S^2 = D\sum_{i=0}^{2} I^i Z^i + 3I_F^0 R_F \quad (3)$$

$$I^A = \sum_{i=0}^{2} I^i \quad (4)$$

Substituting equation (4) into (3),

$$V_S^A = D(I^A + kI^0)Z^1 + 3I_F^0 R_F \quad (5)$$

where,

$$k = \frac{Z^0 - Z^1}{Z^1} \quad (6)$$

The apparent impedance Z_{app} is the ratio of a selected voltage to a selected current.

$$Z_{app} = \frac{V_{select}}{I_{select}} = R_{app} + jX_{app} \quad (7)$$

The selected voltage and currents are determined by the type of fault and the faulted phases. In the example being discussed (single line to ground on phase A) the selected voltage and current are:

$$V_{select} = V_S^A$$

$$I_{select} = I^A + kI^0$$

Therefore,

$$Z_{app} = \frac{V_S^A}{I^A + kI^0} = DZ^1 + \frac{3I_F^0 R_F}{I^A + kI^0} \quad (8)$$

The fault current is also unknown along with the distance and fault resistance, but it can be estimated as the difference between the current in the faulted phase and the prefault current.

$$I_F \cong I^A - I^{Apf} \tag{9}$$

If we take equation (8), substitute in equation (9), and split the equation into real and imaginary parts we will have two equations with two unknowns and be able to solve for both the distance to the fault and the fault resistance.

$$\begin{aligned} R_{app} &= real\{\frac{V_S^A}{I^A + kI^0}\} = real\{Z^1\}D + real\{\frac{I_F}{(I^A + kI^0)}\}R_F \\ X_{app} &= imag\{\frac{V_S^A}{I^A + kI^0}\} = imag\{Z^1\}D + imag\{\frac{I_F}{(I^A + kI^0)}\}R_F \end{aligned} \tag{10}$$

Defining:

$$\begin{aligned} R^1 &= real\{Z^1\} \\ X^1 &= imag\{Z^1\} \\ a &= real\{\frac{I_F}{I^A + kI^0}\} \\ b &= imag\{\frac{I_F}{I^A + kI^0}\} \end{aligned} \qquad \begin{bmatrix} R_{app} \\ X_{app} \end{bmatrix} = \begin{bmatrix} R^1 & a \\ X^1 & b \end{bmatrix} \begin{bmatrix} D \\ R_F \end{bmatrix} \tag{11}$$

Using equation (11) a solution can be obtained for both the distance to the fault and the fault resistance.

$$\begin{aligned} D &= \frac{R_{app}b - X_{app}a}{R^1 b - X^1 a} \\ R_F &= \frac{R_{app}X^1 - X_{app}R^1}{aX^1 - bR^1} \end{aligned} \tag{12}$$

In other faulted conditions there will be different selected voltages and currents in each. They can be determined in a similar manner as shown for the single line to ground fault. A representative list of possible faults is below.

	V_{select}	I_{select}	I_F
SLG A	V^A	$I^A + kI^0$	$I^A - I^{Apf}$
DLG (BC)	$V^B - V^C$	$I^B - I^C$	$(I^B - I^{Bpf}) - (I^C - I^{Cpf})$
LLF (BC)	$V^B - V^C$	$I^B - I^C$	$(I^B - I^{Bpf}) - (I^C - I^{Cpf})$
Three Phase	$V^B - V^C$	$I^B - I^C$	$(I^B - I^{Bpf}) - (I^C - I^{Cpf})$

The apparent impedance method is not consistently accurate on distribution systems, because the assumptions that are made are rarely true for distribution systems.

Appendix II

The Three Phase Fault Location Method

The three phase method, unlike apparent impedance does account for unequal mutual coupling and unbalanced loading conditions.[1-8,11-13] This can be demonstrated by again using a single line to ground fault example shown in *Figure II.1*.

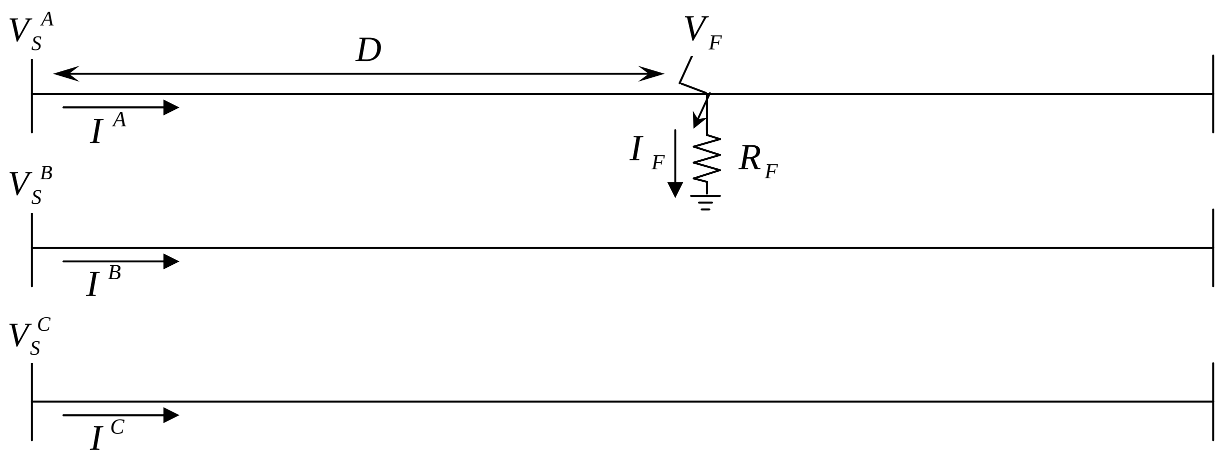


Figure II.1

The voltage for phase A at the substation is:

$$V_S^A = D(I^A Z^{AA} + I^B Z^{AB} + I^C Z^{AC}) + I_F R_F \tag{3}$$

The Z terms are elements of the primitive impedance matrix in ohms per unit length where,

$$\begin{bmatrix} V_S^A \\ V_S^B \\ V_S^C \end{bmatrix} = D \begin{bmatrix} Z^{AA} & Z^{AB} & Z^{AC} \\ Z^{BA} & Z^{BB} & Z^{BC} \\ Z^{CA} & Z^{CB} & Z^{CC} \end{bmatrix} \begin{bmatrix} I^A \\ I^B \\ I^C \end{bmatrix} + \begin{bmatrix} V_F^A \\ V_F^B \\ V_F^C \end{bmatrix} \tag{4}$$

As in the apparent impedance method, fault resistance, distance to the fault, and fault current are all unknown. Using *Figure II.1 t*he fault current can be initially estimated

$$I_F = I^A - I^{Apf} \tag{5}$$

where "*pf*" denotes prefault. The distance and fault resistance can be estimated by separating equation (3) into real and imaginary parts and solving.

$$\begin{bmatrix} V_S^{Ar} \\ V_S^{Ai} \end{bmatrix} = \begin{bmatrix} a & I_F^r \\ b & I_F^i \end{bmatrix} \begin{bmatrix} D \\ R_F \end{bmatrix} \tag{6}$$

Where,

$$\begin{aligned} &V_S^{Ar} = real(V_S^A) \quad V_S^{Ai} = imag(V_S^A) \\ &a = real(I^A Z^{AA} + I^B Z^{AB} + I^C Z^{AC}) \\ &b = imag(I^A Z^{AA} + I^B Z^{AB} + I^C Z^{AC}) \\ &I_F^r = real(I_F) \qquad I_F^i = imag(I_F) \end{aligned}$$

Therefore,

$$\begin{aligned} D &= \frac{V_S^{Ar} I_F^i - V_S^{Ai} I_F^r}{a I_F^i - b I_F^r} \\ R_F &= \frac{V_S^{Ar} b - V_S^{Ai} a}{I_F^r b - I_F^i a} \end{aligned} \tag{7}$$

This method is accurate for fault location for unbalanced distribution systems, but still has errors in the presence of DG. Testing this method with systems containing DG resulted in similar unacceptable errors seen for the apparent impedance method. To account for the presence of DG, the method must be modified.

Appendix III

Accounting For Loads in the System

The basic methods presented in Appendix I and II did not account for loading in the system, therefore in order to study the effect of DG, the loading of the system must be accounted for. Both methods assume there are no loads between the substation and the fault, so the basic modification that can be made to account for loads is to calculate the voltage and current at the nearest load to the fault.

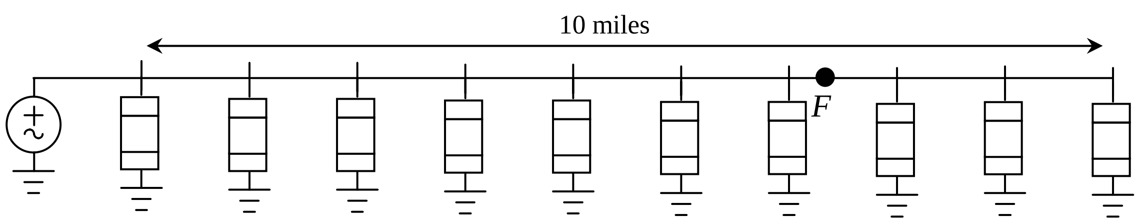


Figure III.1

To demonstrate this, in the given system in Figure III.1 consider a single line to ground fault occurrence at point *F* which is assumed to be at 7.3 miles from the substation on phase A. Using apparent impedance and the three phase method, two different estimations of the fault location can be calculated.

The apparent impedance estimation:

$$D = \frac{R_{app}b - X_{app}a}{R^1 b - X^1 a} = 7.738mi$$

The three phase method estimation:

$$D = \frac{V_S^{Ar} I_F^i - V_S^{Ai} I_F^r}{a I_F^i - b I_F^r} = 7.428 mi$$

Derivations of these equations are discussed in Appendix I and II. A large source of the error in these estimations is due to the loads between the substation and the fault. Specifically, the current being drawn by the load is assumed by the method to be going towards the fault. The effects of loading in the system are dependant on the fault resistance and the impedance of the feeder.

The estimated fault location in both cases is not adequately accurate. A better estimation cannot be made with the given information, but it can be concluded that the fault is beyond the next load bus. In this particular case, it can be assumed that the fault location is further than one mile from the substation since the first load bus is one mile from the substation. The accuracy can be increased if the voltage at the next load bus and the current being drawn by that load is calculated.

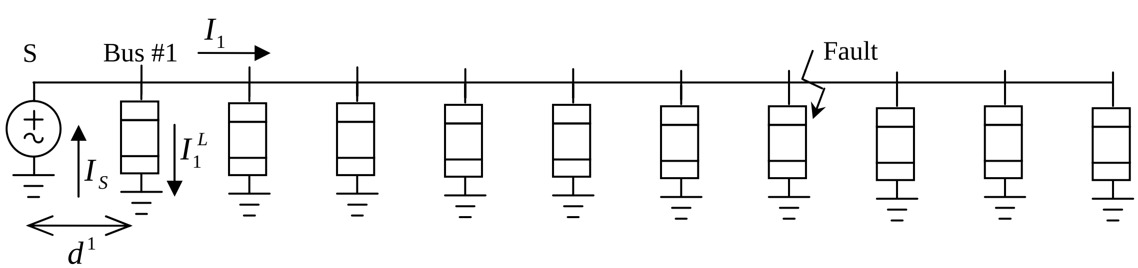


Figure III.2

Using figure III.2 the voltage at bus #1 and the current leaving bus #1 can be calculated.

$$\begin{bmatrix} V_1^A \\ V_1^B \\ V_1^C \end{bmatrix} = \begin{bmatrix} V_S^A \\ V_S^B \\ V_S^C \end{bmatrix} - d^1 \begin{bmatrix} Z^{AA} & Z^{AB} & Z^{AC} \\ Z^{BA} & Z^{BB} & Z^{BC} \\ Z^{CA} & Z^{CB} & Z^{CC} \end{bmatrix} \begin{bmatrix} I_S^A \\ I_S^B \\ I_S^C \end{bmatrix} \qquad (1)$$

Where d^1 is the distance from the substation to bus #1.

$$I_1 = I_S - I_1^L \qquad (2)$$

The current being drawn by the load needs to be calculated in order to solve equation 2 and can be accomplished by solving

$$I_1^L = \left[Z_1^L\right]^{-1}\left[V_1\right] \qquad (3)$$

The load at bus #1 Z_1^L is dependant upon the type of load at that bus.

Next the fault location can be estimated again from the new location and with the new voltage and current values. Continuing in this process, eventually there will be no loads between the fault and the available voltage and current values. Figure III.3 shows the diagram of this method.

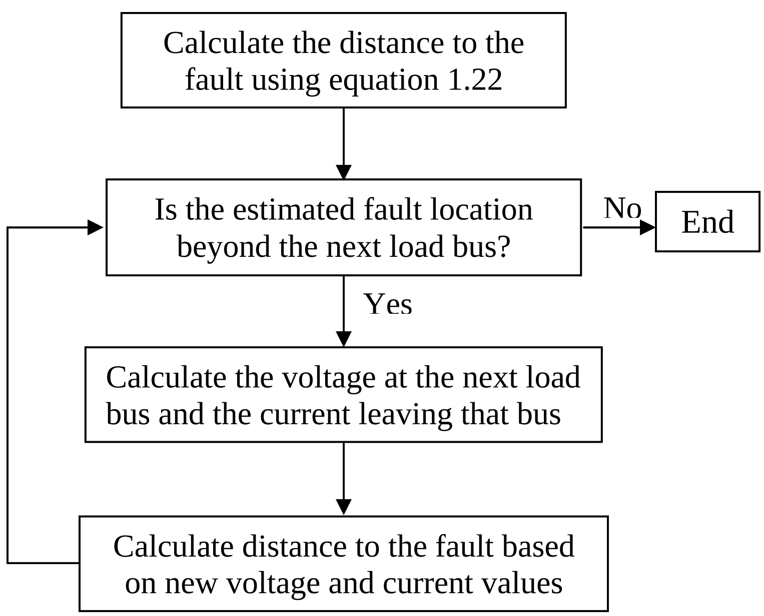


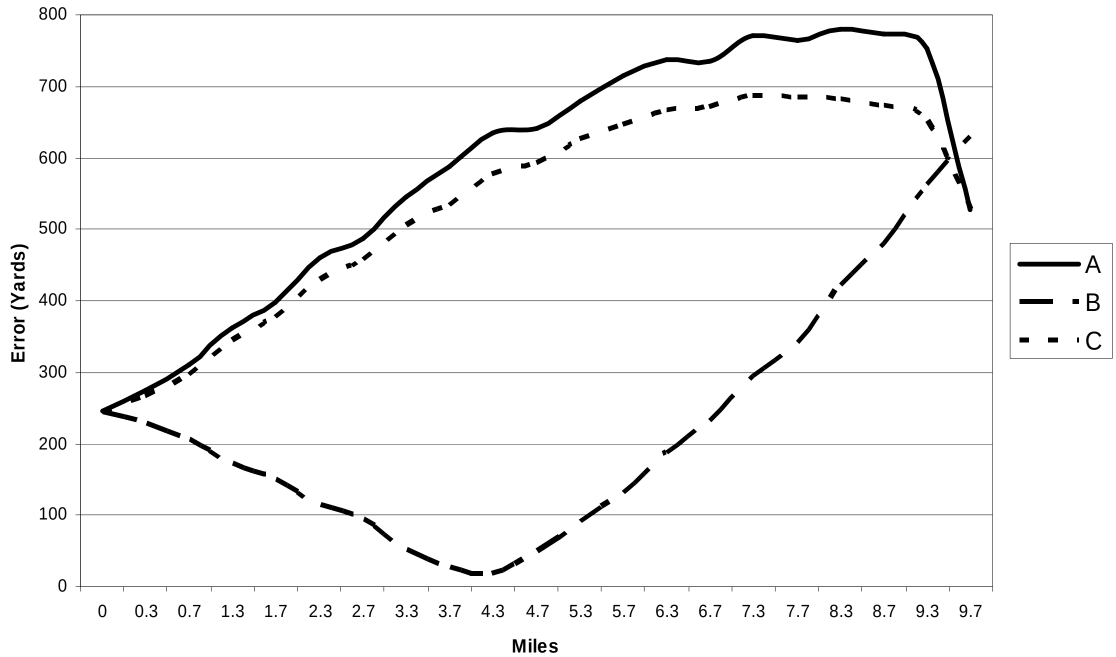
Figure III.3

Figure III.4 shows how the estimated fault location improves over each iteration for the fault example at point *F*.

Figure III.4

Figure III.5 shows the results of the two methods of estimation at various fault locations along the feeder without the load modification. Figure III.6 shows the results for the methods that were accounting for loads.

Apparent Impedance Method



Three Phase Method

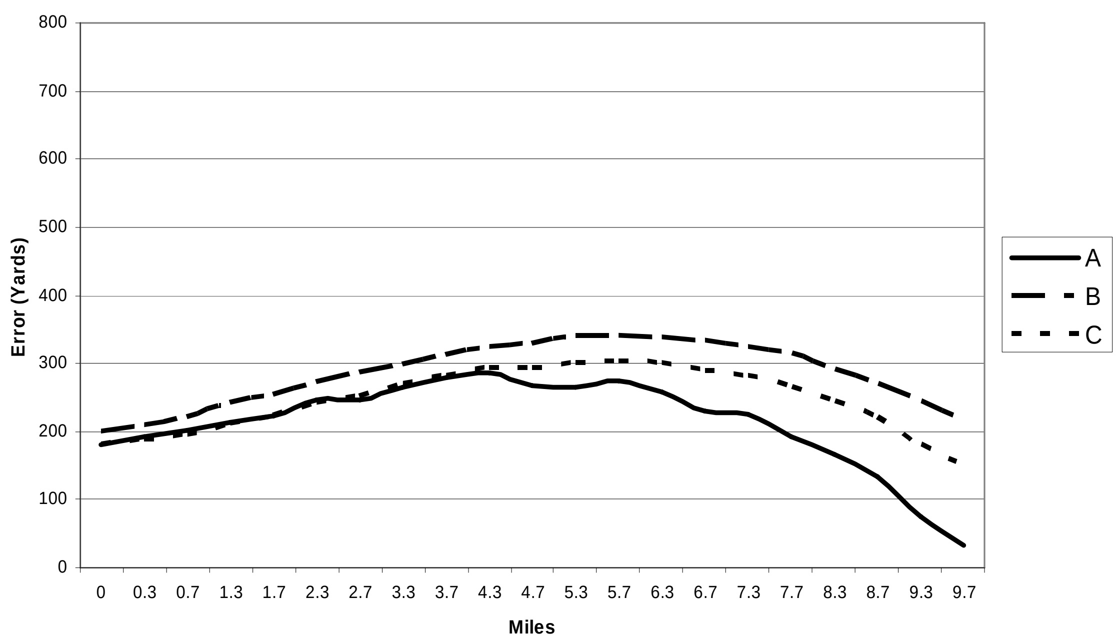
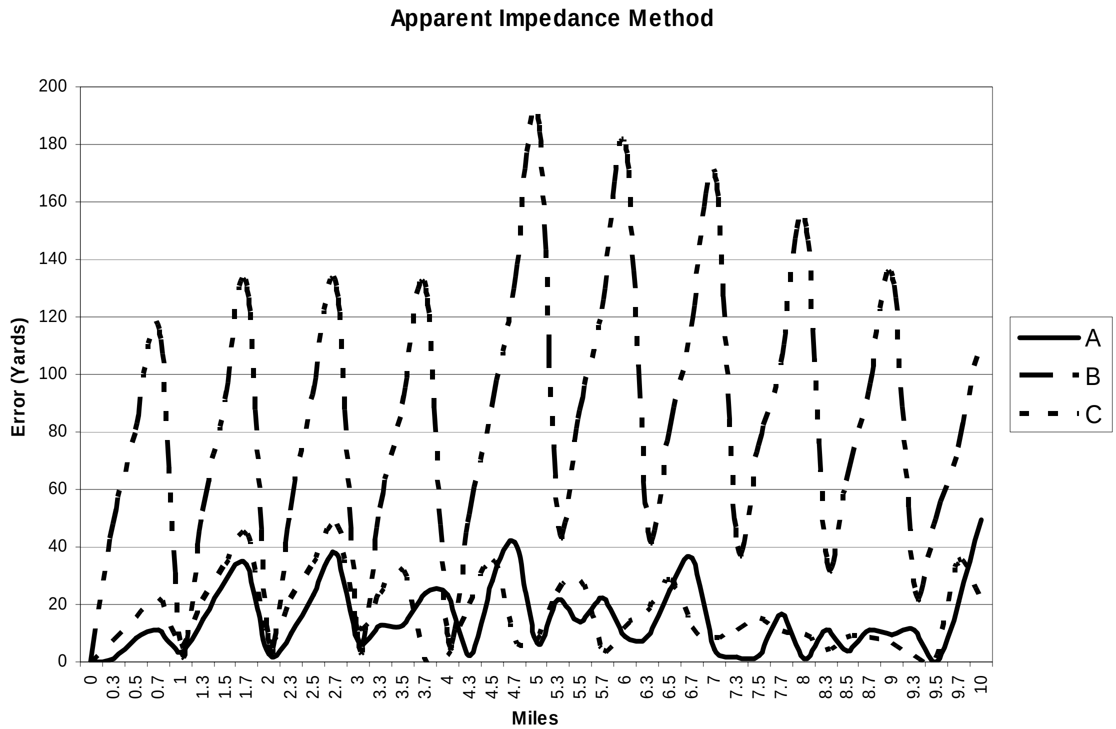


Figure III.5


Apparent Impedance Method
Error (Yards)
Miles
A
B
C

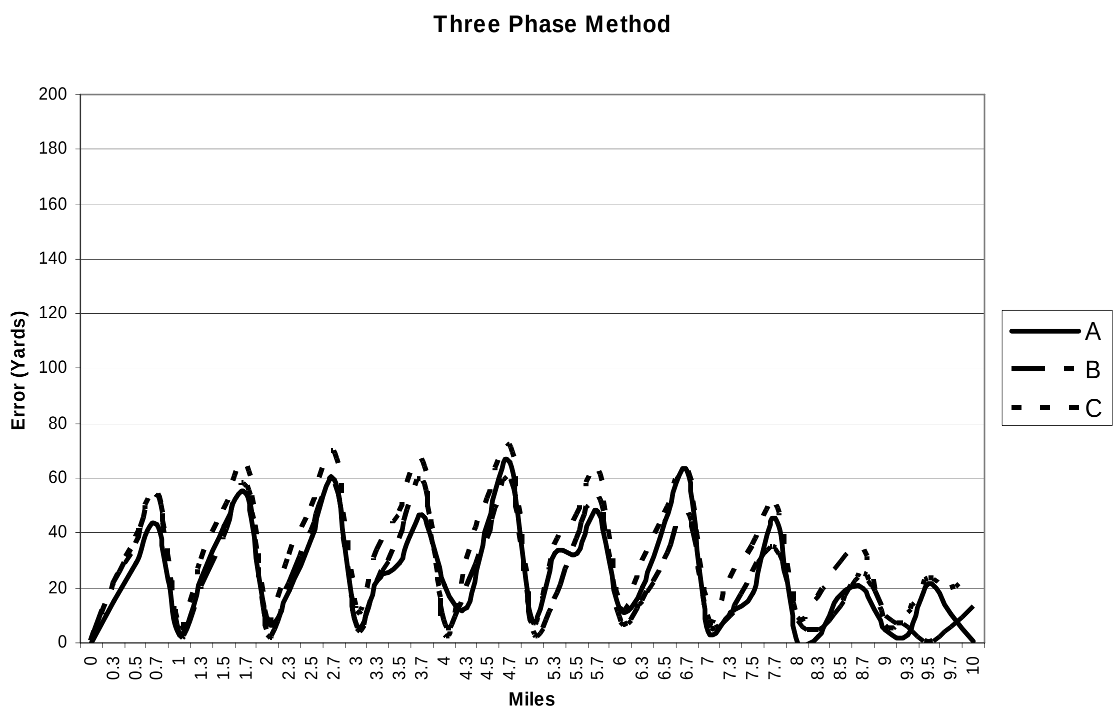

Three Phase Method
Error (Yards)
Miles
A
B
C

Figure III.6

Appendix IV

The Modified Three Phase Fault Location Method

The nature of distributed generation on a system during a fault makes it necessary to have certain information about each DG. This method assumes knowledge of the location of each DG and if they have the capability to feed power back into the distribution system. This alone is not enough information to estimate a fault location because the contribution of the DG to the fault current will be unknown. Secondly, this method assumes that current and voltage waveform data is available at each DG that has the capability to put power back in the system. All of this fault data would in addition have to be synchronized. The DG that cannot feed power back into the system will trip out immediately and will not supply any fault current.

The method was developed and tested on the system shown in *Figure IV.1* which is a ten mile distribution system with three DG and 10 MVA of equally distributed load.

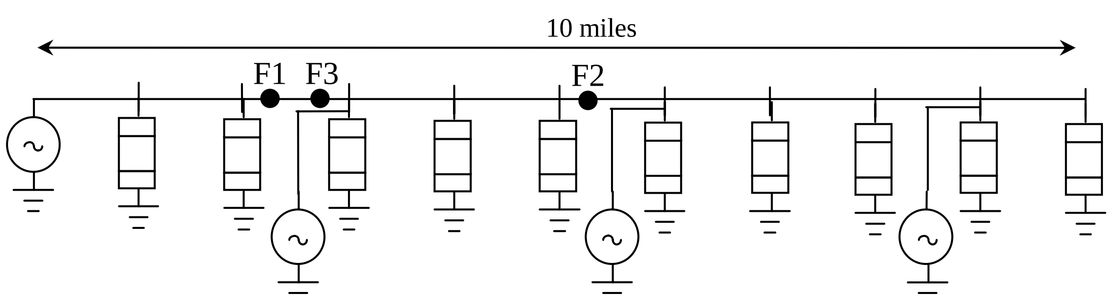


Figure IV.1

This system is not a real system, but it will be used for simplicity of explanation. The principles developed can be easily adapted to a real system.

There are three major areas on the feeder where a fault could occur that need to be addressed. The first case is when the fault is located between the substation and the first DG. The next case is any fault that is between any two DG. The third case is when the fault is beyond the last DG on the feeder. Each of these cases will be presented using an example.

Case One

The first case can be explored using a single line to ground fault on the system shown in *Figure IV.1* at point *F1* that is assumed to be 2.3 miles from the substation. Because this fault is before the first DG, it is in the first case. Using the previous three phase method, an estimation of the fault location can be made using fault data from the substation which results in an estimate of 2.97 miles. A relatively close estimate of the fault location can be obtained when the fault is before the first DG. This estimate is in error by over a half a mile which can be greatly improved. First a better estimate can be obtained by accounting for the loads between the source and the fault. The voltage and currents at the last load bus before the fault should be calculated. At the bus two miles from the substation, an estimation of the fault location can be calculated which would be 2.87 miles. This estimate is an improvement, but certainly not a notable one. The next step is to account for the fault current coming from the DG in the system using the fault data that is available at each DG. This will be discussed in case two.

Case Two

Consider the case of a single line to ground fault on the system in *Figure IV.1* at point *F2* that is assumed to be 5.3 miles from the substation. The position of this fault is between the first and second DG, therefore it is not beyond the last DG or in first case. Using the previous three phase method, an estimate of the fault location would result in an estimate of 19.5 miles. This estimate is not close to where the fault is located, and is even beyond the physical parameters of the distribution system. The reason that the estimated fault location has such high error is because it is neglecting the DG contribution to the fault current. In this example the current at the substation on the faulted phase was only as high as 2.5 pu while in the case of no DG the current was as high as 4.5 pu. In different systems this effect could vary significantly.

The estimated fault location of *F2* is again 19.5 miles, therefore it is reasonable to assume that *F2* is beyond the first load bus. As in case one, the voltage and currents at the next bus can be calculated which is one mile from the substation. At this bus, a new estimate of the fault location is calculated. Continuing this process, the results at bus one and two are 20.63 and 21 miles respectively. This would lead to calculating the voltage and currents at bus three, but there is a DG at this bus. From the fault location estimation of 21 miles, it can be assumed that the fault is beyond the DG at bus three. Therefore, the voltage at this bus and the current feeding, the load is calculated just as before, but the current that is leaving this bus cannot be calculated the same because of the injected current by the DG. The current injected by the DG can be accounted for using the following equation.

$$I_3 = I_2 - I_3^L + I_3^G \tag{8}$$

Now a new estimate of the fault location can be made using the same basic three phase method. The results of this estimate will be similar to the results in case one because there is no DG between the available voltage and current values and the fault. In this particular case, the estimated location was 5.1 miles. Continuing in this process, the final estimation would be at bus five and has a value of 5.17 miles. This estimate, as in case one, can be improved by using the fault data of the other two DG.

To include the data available from the DG, the results from all previous estimations will be ignored. Using the last DG on the feeder, an independent estimation of the fault can be obtained. This estimation will be identical to the method used when considering the substation fault data, with a few minor exceptions.

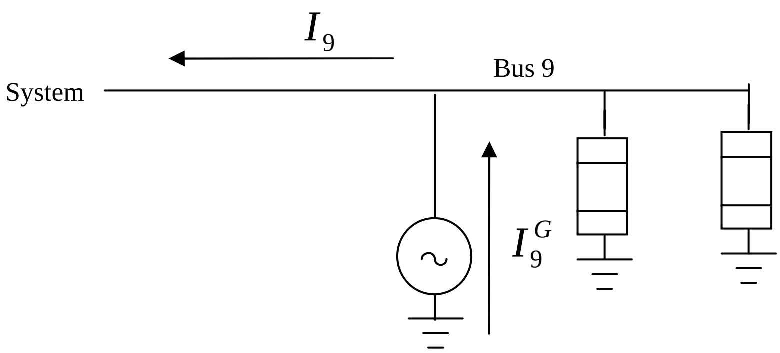


Figure IV.2

The voltage at bus nine and the current I_9 as shown in Figure IV.2 would be needed to calculate the fault location from the DG at bus #9. The fault recorder will not be recording I_9 so it must be estimated. First an equivalent load composed of all loads and feeder losses beyond the DG must be calculated.

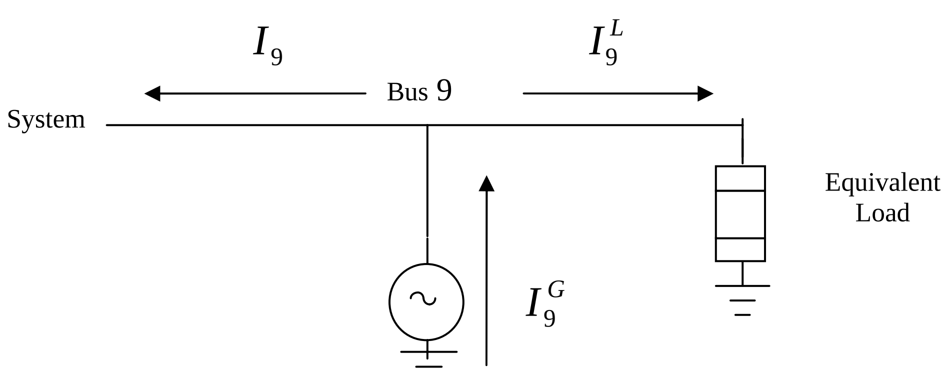


Figure IV.3

The current I_9 can then be calculated.

$$I_9 = I_9^G - I_9^L \quad (9)$$

Where,

$$I_9^L = \left[Z_9^{EL}\right]^{-1}\left[V_9\right] \quad (10)$$

Now that the voltage at bus nine and I_9 are both known, an estimate of the fault location can be calculated using the same basic three phase method. In the example being discussed, the estimated fault location was found to be 5.3 miles from the DG at bus #9. This would correspond to a distance of 3.7 miles from the substation. Calculating the voltages and currents iteratively until the estimated fault location is not beyond the next load bus led to a final estimate at bus #6 that was 3.73 miles from bus #9 or 5.27 miles from the substation. This estimate is better than the estimate calculated using the substation fault data, but that will not be true in every case.

Now two estimates of the fault location has been calculated. The major source of error in both cases is the estimation of the fault current. *Figure IV.4* describes the current situation.

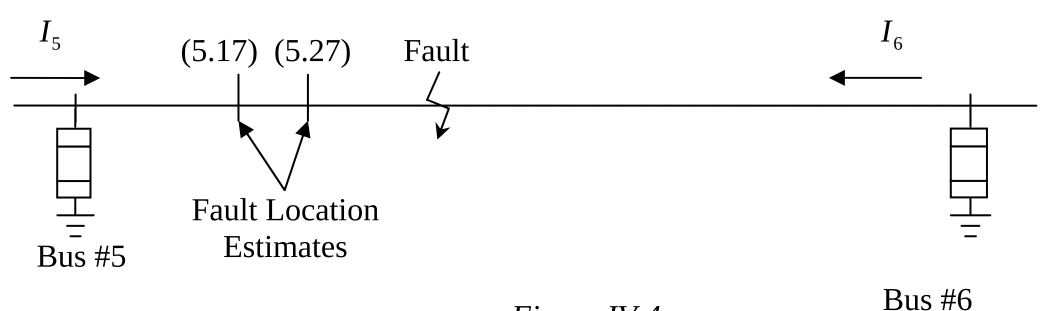


Figure IV.4

More important than the two estimates of the fault location is the calculation of the currents coming from bus five and six. Because there are no loads between bus five and six the fault current no longer needs to be estimated but can be calculated.

$$I_F = I_5 + I_6 \quad (11)$$

With this accurate calculation of the fault current, one final calculation of the fault location can be made. The result is an estimate of 5.30 miles. The accuracy of this method will be further discussed later in this paper.

Case Three

The final case is when the fault is beyond the last DG. Unlike case one and two, there is not a possibility to get two independent estimates, but it is not needed. The voltage and current measurements at that last load bus before the fault would be calculated as in the other two cases. This would give the best estimate.

Special Cases

The described methods above make one major assumption for cases one and two. This assumption is regularly not true in system involving DG. The assumption is that both estimates of the fault location will be between the appropriate load busses. For example, consider a fault at point *F3* that is assumed to be at 2.7 miles from the substation on the system in Figure IV.1. Following case one, it would be expected that the last estimate made from the substation fault data would be at bus #2. The estimated fault location at bus #2 is 3.1 miles. Strictly following the method presented would lead to an estimate at bus #3 which is beyond the fault. The result of an estimation at bus #3 in this example would be 3.0 miles. The method has gone one load bus too far in its estimation. This is a very common occurrence when the fault is very close before a DG bus. If this is ignored as a problem and an estimate is then acquired from the last DG at bus #9 in this case, the result would be 8.4 miles. So, one estimate says 3 miles while the other says 8.4 miles. Continuing this method would not result in an accurate calculation of the fault current because there are many loads and a DG between bus #3 and bus #9.

The solution of this problem is twofold. First, force the second estimate to be consistent with the first. In the example being discussed, the second estimate would continue until it reached bus #4. The resulting estimate would be 3.4 miles.

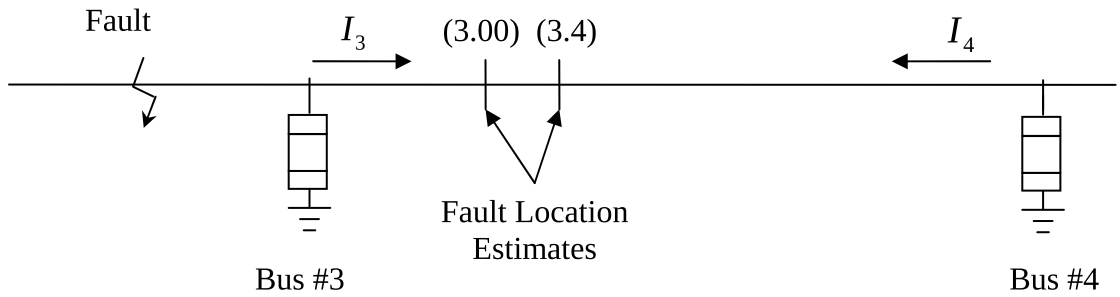


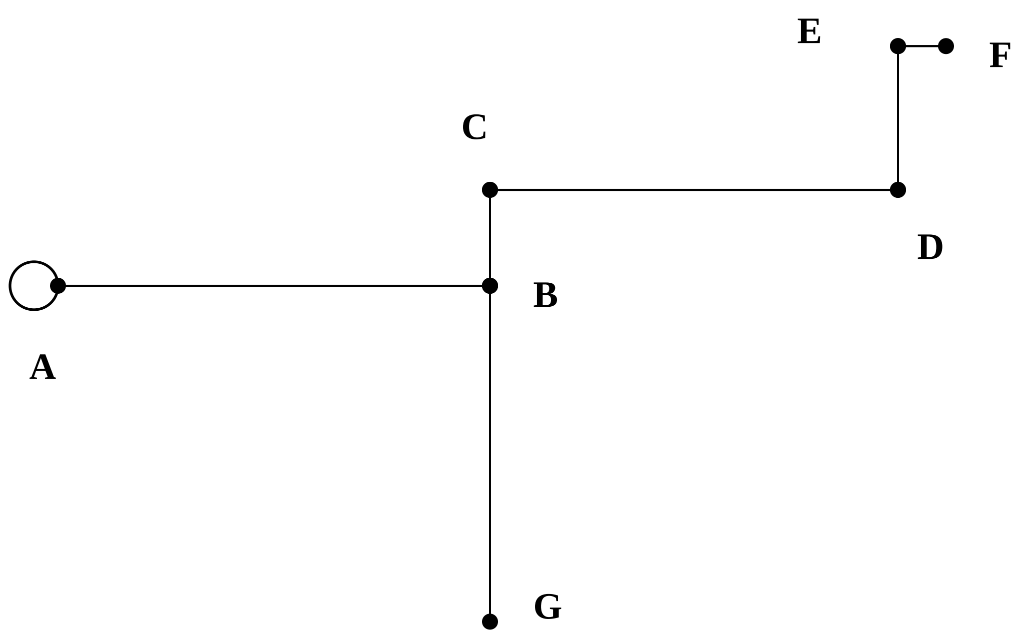
Figure IV.5

The addition of the I_3 and I_4 will not give an accurate fault current, but if the method is continued assuming that the fault is between bus three and four, then the final fault location using the calculated fault current will give an interesting result. The calculated distance will be negative if the fault is before bus three. Therefore the final fault location estimation will be 2.96 miles. This estimation is not accurate, but it is also not consistent with the first estimate which determined that the fault was beyond bus #3. With this knowledge, we can begin the whole process again, and force the first estimate to stop at bus #2 and the second estimate to continue till bus #3. Using these two estimates, the fault current can be accurately calculated, and a final accurate estimate can be made. In this example, the final estimate of the fault location was 2.70 miles.

This type of error can occur by both overshooting and undershooting the fault location. The final result must be compared with the two initial estimates and confirmed that they are consistent with one another. If they are not consistent, then a correction can be made by setting up a boundary condition for the method and restarting the process.

Appendix V

Real System Data



Point A – Substation

Trf – 10 MVA
Voltage – 44KV – 12.47Y/7.2 KV
Trf Imp – 6.77 % (10 MVA base)
Source Imp (including Trf on a 100 MVA base):
Z1 = 3.01% + 76.84%
Z0 = 3.01% + 67.63%
Peak Load:
A = 227 A @ 99.63 % pf
B = 250 A @ 99.55 % pf
C = 256 A @ 99.49% pf

Point A – B :

Distance =14,780’
Phase Conductors = 336 ACSR
Neutral Conductor = 1/0 ACSR
Spacing = 54”

Point B – C:

Distance = 826’
Phase Conductors = #2 ACSR
Neutral Conductor = #2 ACSR
Spacing = 54”

Point C – D:

Distance = 3926’
Phase Conductors = #4 Bare Copper
Neutral Conductor = #4 Bare Copper
Spacing = 54”

Point D – E:

Distance = 1109’
Phase Conductors = 1/0 ACSR
Neutral Conductor = 1/0 ACSR
Spacing = 54”

Point E – F:

Distance = 256’
Phase Conductors = #2 ACSR
Neutral Conductor = #2 ACSR
Spacing = 54”

Point F – Generator #1

Active Generation = 1250 KW
Generator Voltage = 4.16 KV (ungrounded wye)
Power Factor = 80%
Max Reactive Generation = 936 KVAR
Min Reactive Generation = 251 KVAR
Z1 = 1.7 % + 20.69% (100 MVA base)

Point F – Transformer

Nominal Rating = 2000 KVA
Primary Voltage = 12.47 KV wye
Secondary Voltage = 4.16 KV delta
Imp = 5.57%
X/R = 4.9

Point B- G

Distance = 10,069’
Phase Conductors = #2 ACSR
Neutral Conductor = #2 ACSR
Spacing = 54”

Point G – Generator #2

Active Generation = 1000 KW

Generator Voltage = 0.6 KV (ungrounded wye)

Power Factor = 80%

Max Reactive Generation = 750 KVAR

Min Reactive Generation = 200 KVAR

Z1 = 1.7 % + 20.69% (100 MVA base)

Point G – Transformer

Nominal Rating = 2000 KVA

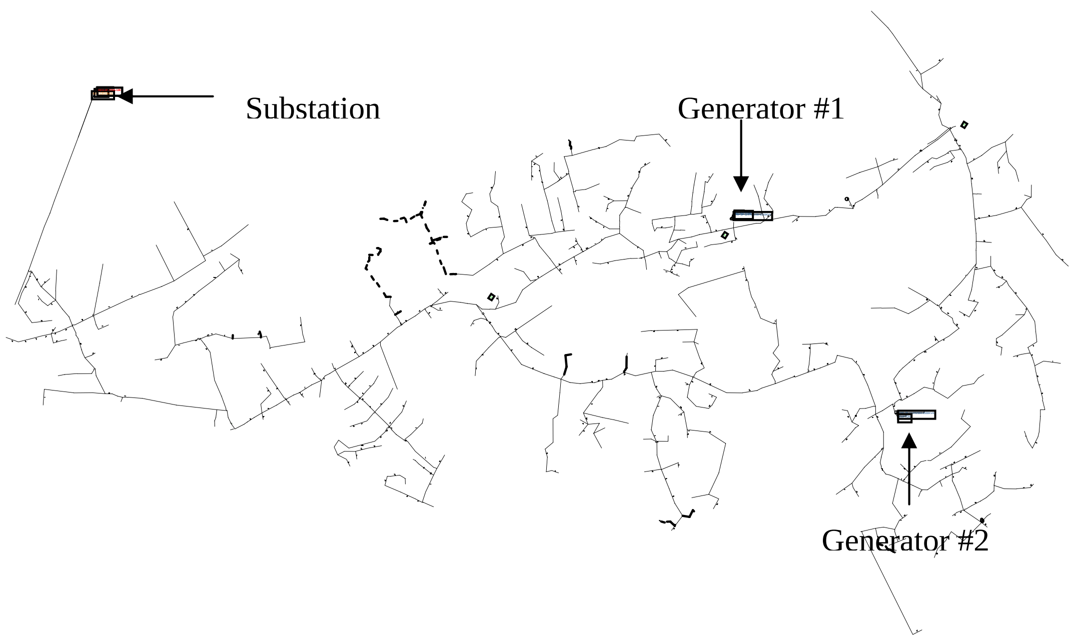
Primary Voltage = 12.47 KV delta

Secondary Voltage = 0.6 KV delta

Imp = 5.4 %

X/R = 4.9

Below is a map showing the circuit configuration.



California Energy Commission Energy Innovations Small Grant (EISG) Program **PROJECT DEVELOPMENT STATUS**	***Questionnaire***

Answer each question below and provide brief comments where appropriate to clarify status. If you are filling out this form in MS Word the comment block will expand to accommodate inserted text.

Overall Status	
Questions	**Comments:**
1) Do you consider that this research project proved the feasibility of your concept? **YES**	*Briefly state why.* **The main goal was the development of an accurate and fast fault location technique for distribution systems with distributed generation. The developed technique was tested for all types of faults. The average error is about .5 % of the feeder length. The time from fault occurrence to the computation of fault location is about 50 m sec.**
2) Do you intend to continue this development effort towards commercialization? **NO**	*If NO, indicate why and answer only those questions below that are still relevant.* **The technique can be added to the software of microprocessor based relays (currently available). Furthermore, the university is not well equipped for commercialization plans.**
Engineering/Technical	
3) What are the key remaining technical or engineering obstacles that prevent product demonstration?	**Testing on actual fault data due to real life faults on a distribution feeder that contains distributed generation.**
4) Have you defined a development path from where you are to product demonstration? **NO**	**The developed scheme can be implemented on existing devices.**
5) How many years are required to complete product development and demonstration? **N/A**	
6) How much money is required to complete engineering development and demonstration?	*Do not include commercialization costs such as tooling.*
7) Do you have an engineering requirements specification for your potential product?	*This specification details engineering and manufacturing needs such as tolerances, materials, cost, stress etc. If NO indicate when you expect to have it completed.*
Marketing	
8) What market does your concept serve?	*Residential, commercial, industrial, other.*
9) Is there a proven market need?	*If YES, what sources did you use to determine market need?*

10) Have you surveyed potential end users for interest in your product?	*If YES, the results of the survey should be discussed in the Final Report.*
11) Have you performed a market analysis that takes external factors into consideration?	*External factors include potential actions by competitors, other new technologies, or changes in regulations or laws that can impact market acceptance of your product?*
12) Have you compared your product with the competition in terms of cost, function, maintenance etc.?	
13) Have you identified any regulatory, institutional or legal barriers to product acceptance?	*If YES, how do you plan to overcome these barriers?*
14) What is the size of the potential market in California?	*Identify the sources used to assess market size.*
15) Have you clearly identified the technology that can be patented?	*If NO, how do you propose to protect your intellectual property?*
16) Have you performed a patent search?	*If YES, was it a self-search or professional search and did you determine if your product infringes or appears to infringe on any other active or expired patent?*
17) Have you applied for patents?	*If YES, provide the number of applications.*
18) Have you secured any patents?	*If YES, provide the patent numbers assigned and indicate if they are generic or application patents.*
19) Have you published any paper or publicly disclosed your concept in any way that would limit your ability to seek patent protection?	*If YES, is it your intent to put the intellectual property into the public domain?*
Commercialization Path	
20) Can your organization develop and produce your product without partnering with another organization?	*If YES, indicate how you would accomplish that.* *If NO, indicate who would be the logical partners for development and manufacture of the product.*
21) Has an industrial or commercial company expressed interest in helping you take your technology to the market?	*If YES, are they a major player in the marketplace for your product?*
22) Have you developed a commercialization plan?	*If yes, has it been updated since completing your grant work?*
23) What are the commercialization risks?	*Risks are those factors particular to your concept that may delay or block commercialization.*
Financial Plan	
24) If you plan to continue development of your concept, do you have a plan for the required funding?	
25) Have you identified funding requirements for each of the development and commercialization phases?	

26) Have you received any follow-on funding or commitments to fund the follow-on work to this grant?	*If YES, indicate the sources and the amount.* *If NO, indicate any potential sources of follow-on funding.*
27) Have you identified milestones or key go/no go decision points in your financial plan?	
28) What are the financial risks?	
29) Have you developed a comprehensive business plan that incorporates the information requested in this questionnaire?	*If YES, can you attach a non-proprietary version of that plan to your final report?*
Public Benefits	
30) What sectors will receive the greatest benefits as a result of your concept? **Residential, Commercial, and Industrial**	*Residential, commercial, industrial, the environment, other.* **Distribution systems distribute power to commercial, residential and industrial loads. Thus, all types of loads will benefit from the improved reliability due to reducing the outage time of faulted feeders.**
31) Identify the relevant savings to California in terms of kWh, cost, reliability, safety, environment etc.	*Show all assumptions used in calculations.*
32) Does the proposed technology impact emissions from power generation? **N/A**	*If YES, calculate the quantity in total tons per year or tons per year per relevant unit. Show all assumptions used in calculations.*
33) Are there any potential negative effects from the application of this technology with regard to public safety, environment etc.? **NO**	*If YES, please specify.*
Competitive Analysis	
34) Identify the primary strengths of your technology with regard to the marketplace.	*Identify top 3.* **1. Accuracy** **2. Speed** **3. Application to typical feeder of multiphase laterals**
35) Identify the primary weaknesses of your technology with regard to the marketplace.	*Identify top 3.* **1. The need to obtain fault data from all distributed generators** **2. The need to have all fault data synchronized** **3. Load modeling**
36) What characteristics (function, performance, cost etc.) distinguishes your product from that of your competitors?	**This method does not use the simplifying assumptions used in other methods.**
Development Assistance	
The EISG Program may in the future provide follow-on services to selected Awardees that would assist them in obtaining follow-on funding from the full range of funding sources (i.e. Partners, PIER, NSF, SBIR, DOE etc.). The types of services offered could include: (1) intellectual property assessment; (2) market assessment; (3) business plan development etc.	
37) If selected, would you be interested in receiving development assistance?	*If YES, indicate the type of assistance that you believe would be most useful in attracting follow-on funding.*