TECHNICAL REPORT WORKING GROUP D45 ON PROTECTION METHODS USED TO REDUCE WILDFIRE RISK DUE TO TRANSMISSION AND DISTRIBUTION LINES

Chair: Jonathan Sykes
Vice-chair: Scott Hayes
Secretary: Bruce Mackie

Members and Contributors

Galina Antonova
Hugh Borland
Ritwik Chowdhury
Normann Fischer
Matt Garver
Wayne Hartmann
Scott Hayes
Craig Holt
Daqing Hou
Robbie James
Bogdan Kasztenny
Bruce Mackie
Deepak Maragal
Boris Marendic
Tony Marxsen
Nirmal-Kumar C Nair
Russ Patterson
Henry Quin
Farnoosh Rahmatian
Dan Ransom
Matthew Reno
Jesse Rorabaugh
Jonathan Sykes
Andrew Swisher
Douglas Taylor
Eric Udren
Ari Wahlroos
Joe Xavier
Yujie Yin
Amin Zamani

ACKNOWLEDGMENTS

The Working Group is grateful for the support of the Line Protection Subcommittee and the Power System Relaying and Control Committee.

The D45 Working Group acknowledges the efforts of many of the members of the PSRC and all contributors that attended the meetings and moved this subject along to fruition.

KEYWORDS

Keywords (in alphabetical order) to help identify the major topics of thereport.

Arc Suppression Coil

Compensated Neutral

Covered Conductor

Current Limiting Fuse

Expulsion Fuse

Falling Conductor

Fast Trip Settings

High-Impedance Fault

High-Impedance Ground

Ignition Risks

Incipient Fault

Multi-Grounded (4-wire)

Non-Effective Grounding

Pattern Recognition

Petersen Coil

Public Safety Power Shutoff

Pulse Counting

Rapid Earth Fault Current Limiter

Resonant Grounding

Traveling Wave

Uni-Grounded (3-Wire)

Wildfires

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1. INTRODUCTION

Wildfires (bush fires and forest fires) have become more frequent, intense, and damaging in recent years. The impact of fires is made worse by the increased development in wildland-urban interface (WUI) areas and related land management practices that tend to result in large amounts of fuel that can lead to more intense fires. Extending electrical infrastructure into these areas increases the risk of igniting a catastrophic wildfire. Over the last decade, some of these mega fires have approached 400,000 hectares and destroyed more than 10,000 homes in addition to human fatalities and environmental harm. Electrical equipment is not the largest cause of wildfires, but the fires initiated by these tend to become larger and more damaging due to their relationship to the environmental conditions at the time of ignition (i.e., high temperatures, dry fuel, low humidity, and high wind conditions).

1.1 Assignment

The assignment is to prepare a technical report to the line protection subcommittee to "document protection methods used to reduce wildfire risks due to transmission and distribution lines."

1.2 Definitions

Arc Suppression Coil (ASC) – Arc suppression coil (ASC), Petersen Coil, and historically ground fault neutralizers (GFN) are alternative names for an adjustable reactor in the transformer neutral for the purpose of limiting phase-to-ground fault current. This creates a compensated neutral (CN) system or resonant grounded neutral (RGN) system.

Falling Conductor – is used in the context of this document to describe overhead conductors that have broken and are falling. Similar terms are "broken conductor", "open phase", and "downed conductor".

Fast Trip Settings – "Fast Trip Settings" is the term used in this report to describe making settings more sensitive and/or decreasing the time delay to trip. There are other terms being used in the industry that have a very similar meaning.

Ground Fault Neutralizer (GFN) – Historically this term was applied to an arc suppression coil (ASC). This term is now often applied to systems with an ASC and a residual current compensator (RCC). Refer to Residual Current Compensator (RCC) and Rapid Earth Fault Current Limiter (REFCL).

High-Impedance Fault (HIF) – A high-impedance fault (HIF) results when a conductor comes into contact with a highly resistive medium such as a road surface, sidewalk, sod, tree limb, or with some other surface or object which restricts the flow of fault current significantly below what the model predicts is the unrestricted fault level. A fault impedance of 1,000 ohms or more can be assumed as a HIF.[1]

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[1] High Impedance Fault Detection Technology, IEEE PSRC Work Group D15 Report; 1996; 083.pdf (pes-psrc.org)

In addition, a HIF is a fault with an impedance so large that it cannot be detected by fundamental-frequency current and voltage measurement-based relays (i.e., impedance-based distance, differential, overcurrent).[2]

High-Impedance Grounding – High-impedance grounding is when the transformer (wye or delta windings) is connected to the ground grid through an impedance. Some systems are covered in Section 6.5. This contrasts with the connection at the transformer being solidly connected to the ground grid (approximately zero impedance between the transformer and the ground grid). (see also non-effective grounding)

Incipient fault – This term describes a condition that if not treated will lead to a failure, high current fault, or fire ignition. In many cases this condition will create low magnitude electrical signals that may gradually increase over time.

Non-Effective Grounding – Non-effective grounding describes the neutral to earth connection made through a high value resistance or reactance (including an isolated connection) such that the coefficient of grounding/earthing is greater than 80%, as defined in IEEE C62.92.4 and IEC 60044-8.[3] Similar to high-impedance grounding.

Pattern Recognition – A term used to describe the ability to recognize the electrical quantities (voltage, current, etc.) and compare these to known signatures of abnormalities including electrical faults, fault precursors, conductor slap, arcing or momentary opens in disconnects.

Petersen Coil – Refer to Arc Suppression Coil (ASC).

Radial circuit: A type of distribution circuit fed from a single positive sequence source.

Rapid Earth Fault Current Limiter (REFCL) – Rapid earth fault current limiter (REFCL) is a generic term for systems designed to limit the magnitude of ground fault currents to very low levels. This is typically an arc suppression coil (ASC) combined with a residual current compensation (RCC). Please refer to the use of these terms in Section 7.

Residual Current Compensation (RCC) – Residual current compensation (RCC) is an adjustable inverter connected in parallel with an ASC. The RCC injects current into the neutral to cancel out residual fault current on a compensated neutral (CN) system during ground faults.

Wildfires: The term “wildfires” will be used in this document and can be interchangeable with “forest fires” and “bush fires.”

Wildland-Urban Interface (WUI): The wildland–urban interface (WUI) is a zone of transition between wilderness and land developed by human activity – an area where a built environment meets or intermingles with a natural environment. Human settlements in the WUI are at a greater risk of catastrophic wildfire.

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[2] High Impedance Faults; CIGRE Working Group B5.94; December 2009

[3] Non-effective grounded is defined in international standards IEEE C62. 92.4-2014 and IEC 60044-8, Version 1.0 (2002-07)

1.3 Key Abbreviations and Acronyms

ACSR	aluminium conductor steel reinforced	LCD	line current differential
ASC	arc suppression coil	MFA	multi-frequency admittance
CN	compensated neutral	PSPS	public safety power shutoff
CLF	current limiting fuse	qu	charge voltage
DER	distributed energy resources	RCA	relay characteristic angle
DLD	distribution line differential	REFCL	rapid earth fault current limiter
FIT	fault inception transient	RCC	residual current compensation
FPG	faulted phase grounding	SCADA	supervisory control and data acquisition
FPI	fault passage indication	SGF	sensitive ground fault (protection)
GFN	ground fault neutralizer	TOV	temporary overvoltage
HIF	high-impedance fault	TW	traveling wave
IBR	inverter-based resources	UV	ultraviolet
ICR	impedance change ratio	VT	voltage transformer
IN	isolated neutral	Y0	zero-sequence admittance

2. SCOPE

It is not possible to eliminate all the risk of electrical infrastructure igniting fires for many reasons. The electrical grid was created and expanded over more than 100 years and required electrical transmission and distribution lines to be built in and around WUI. When the electrical system contacts combustible material (i.e., trees, grass, organic debris, wood, etc.) within these areas there is the release of energy that manifests in an electrical arc and heat. If the environmental conditions of dry fuel, warm or hot ambient temperature, and wind are present then a wildfire can be started. The industry refers to the electrical contact as a fault. Faults and failures, which can occur on all electrical equipment present ignition risks in various forms such as sparks, arcing, and flaming debris. However, there are methods that can be used to reduce risks of these failures from igniting wildland fires. Many of these methods are outside of the purview of the PSRC and will not be addressed in this report. (i.e., vegetation management, overhead to underground or covered conductor conversion, enhanced inspections, Public Safety Power Shutoff - PSPS, etc.) This report includes protective relay, electrical sensor-based methods, and other techniques used to detect and clear problems on transmission and distribution lines that could ignite wildfires. It also includes discussions of some selected technologies that can change fault characteristics, increase the speed of fault clearing, and/or reduce the energy available at the arc or contact point.

This report documents methods and technologies that protection engineers can apply to reduce the number of faults, fault energy, and the probability of power system faults igniting wildfires. There is no single method available that will prevent faults on overhead transmission and distribution lines from igniting fires. There are several methods discussed in this report that can reduce ignition risk. For example, some of these methods only apply to specific grounding systems and some will only reduce the risk of ignition for line-to-ground faults.

This report introduces some emerging technologies and applications, and the study to prevent wildfires is producing new applications very quickly and not all emerging efforts can be covered in the report. Other areas that are not explored in this report are risks associated with low-voltage systems such as those providing delivery of electrical power from the distribution transformer to the individual home or commercial facility. The only protective devices for service or secondary systems are generally the source side protection for the service transformer that usually consists of fuses. This protection is applied to protect the transformer and will not provide fast isolation for faults on these low-voltage systems.

It is appropriate to mention the comparison between electric service reliability and reduction of wildfire risks. These two concepts can be in opposition. Utilities have been required to maintain reliability of the grid which creates designs that limit the impact of faults and failures on the grid by minimizing the loss of customers or the duration in time that an outage occurs. Wildfire mitigation focuses on the reduction of energy at the point of contact with combustible material and does not have an emphasis on reliability. Thus, wildfire mitigation can negatively impact reliability and will frequently compromise fault isolation coordination. Practitioners, owners, and regulators will need to find the balance between reliability and wildfire risk mitigation based on requirements and priorities.

As with all engineering decisions, applying the methods described in this report involves analyzing the tradeoffs between increased sensitivity and large outages, which can also have a negative impact on wildfire risk. In the effort to balance these risks, engineers, regulators, and owners might reach very different decisions based on local conditions. Since there are many methods that may reduce risks, some companies might decide to apply multiple methods within their system. Many companies might choose to apply defense in depth by selectively applying several different methods in portions of their system.

3. FAULT BEHAVIOR AND IGNITION RISK

The potential of electrical phenomena, such as lightning and arcing from modern electrical equipment, to ignite wildfires is well-established. This has led to the creation in the USA of the National Electrical Code (NEC) to mitigate these risks, developed by the National Fire Protection Association (NFPA) beginning in 1897. At a fundamental level, fire ignition risk increases with an increase in fault energy. Fault energy is a function of the magnitude of fault current and the duration of the fault. However, the variety of fault conditions that occur on the power system factored in with fuel bed and climate conditions make for a much more complicated picture.

This section will explore the various factors involved in how the electric system can cause a wildfire either by direct contact with dry fuel (direct contact faults) or by molten and very hot particles dropping onto dry fuel (overhead arcing faults). Direct contact faults can include combustible material touching energized conductors or the arc contacting combustible material. Section 3.5 will provide more detail on the gaps of understanding the risk associated with how these conditions and the amount of fault current can cause a wildfire.

3.1 Transmission and Distribution Line Faults

The arc energy, that is the heat energy of an electrical arc calculated as I^2t*R, with voltage absent from the expression, highlights the similarity between transmission and distribution lines with respect to fault behavior and ignition risk. In subsequent sections of this report, it will be shown that current as opposed to voltage is the quantity of greatest importance. Similar fault duties can be found on both transmission and distribution lines, enabling the combination of the two into a single analysis of overhead line faults, irrespective of their transmission or distribution classification. Before this more general treatment, first note the differences between transmission and distribution line fault behavior and ignition risk. It is the voltage that establishes the path by which fault current can flow, making high-impedance faults more prevalent at lower voltages, where the lower voltage drop struggles to establish a low-impedance path to ground (or, for example, a path between phases through a tree branch). High-impedance faults can present unique ignition risks due to the possibility of very slow trip times, with some fault conditions being completely undetected by traditional and legacy protection systems. Additionally, increased voltage exacerbates the phenomenon of higher electric fields concentrated at sharp points of conductors, increasing the likelihood that a fault will arc to that single sharp point on the conductor, resulting in a much higher ignition risk that will be covered in more detail in Section 3.3 for overhead arcing faults.

I^2t*R is the equation for the energy of the electrical arc, in Watt-seconds or Joules, where I is the current, t is the duration of the arc, and R is the arc resistance.

It is the energy at the arc that can ignite the fuel that the arc comes in contact with. This power can be lower but present longer, or higher and present for a small amount of time. Both situations can produce enough heat energy to ignite fuel that could be present.

There are also a variety of physical factors that decrease the ignition risk profile of transmission lines versus distribution, including the proximity of trees and other vegetation to the lines as well as growth beneath the lines, height above ground, conductor spacing, and the stoutness of transmission construction over distribution. The grounding at the structure whether it be a metal lattice structure or wood pole can also be a factor to reduce the energy at the contact point with fuel. If the grounding of the structures is solid and makes good contact with the ground, then the fault energy will dissipate into the ground. Additionally, transmission systems are generally less expansive with fewer taps than distribution systems and consequently, the transmission protection systems are point to point and often utilize communications-assisted schemes, with fault detection and isolation coverage over 100% of the line with no intentional time delay.

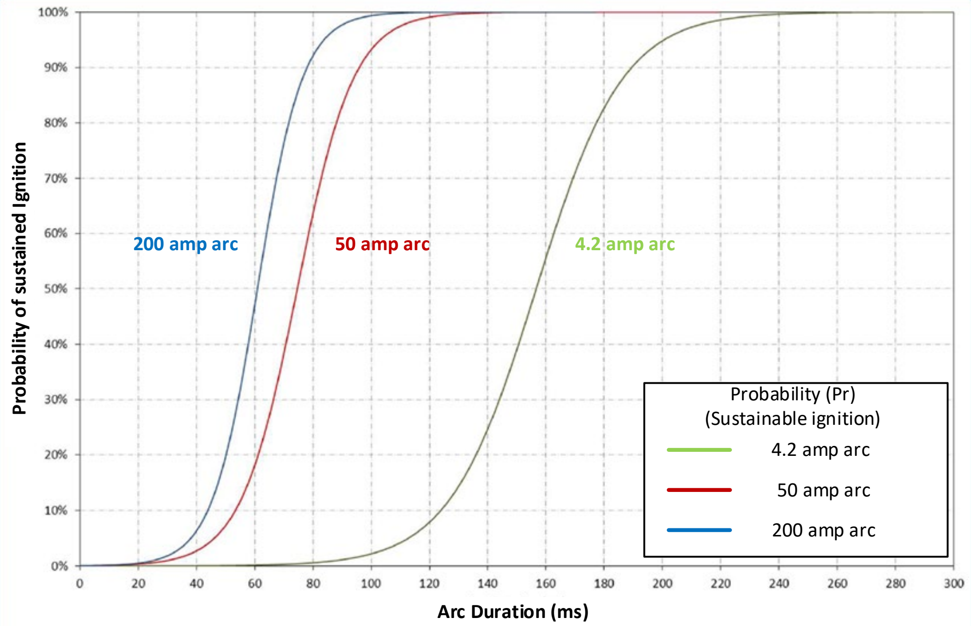
Transmission and distribution line faults can be classified into three basic fault types: phase faults (e.g., phase-to-phase faults); ground faults (e.g., phase-to-ground faults); and a combination of the two (e.g., phase-to-phase-to-ground faults). Although these categories make sense when discussing the response of protection systems, they do not neatly align with the fundamental mechanisms that start fires. For the purposes of understanding fire risk, they can more accurately be divided into two categories that are determined by the path of current flow and proximity of the fuel to the location of the electrical arc. Some examples are direct contact faults such as conductors on the ground or trees contacting a line, and overhead arcing faults. In a direct contact fault, current flows through the fuel source (e.g., current flows through vegetation when in contact with an energized conductor) and puts the I^2t*R energy of the arc in direct contact with the fuel source. In an overhead arcing fault, current flows through the air (e.g. two conductors slapping or clashing together, or conductor arcing to a tower). The I^2t*R energy of the arc itself does not pose any direct fire risk because its energy is simply dissipated into the air, ejecting hot metallic particles from the surface of the conductors at the location of the arc. These particles have the potential to come into contact with a fuel source at a significant distance from the arc.

While at first glance it might appear that direct contact faults and overhead arcing faults correspond to ground faults and phase faults respectively, there are examples for which this one-to-one correspondence does not hold. A tree limb bridging the gap between two conductors can cause a phase-to-phase fault that ignites the tree limb due to the direct contact of the arc with the vegetation. A phase conductor arcing to a tower can cause a phase-to-ground fault that ignites dry vegetation on the ground due to the hot aluminum and steel particles resulting from this overhead arcing fault. Although fires started by high-impedance faults are often associated with an arc directly contacting vegetation (e.g. a phase conductor contacting a tree), the previous example of a phase conductor arcing to a tower (e.g. an overhead arcing fault) can result in an extremely high-impedance fault depending upon the effectiveness of the tower grounds.

The I^2t*R energy of a fault is the primary source of fire ignition. However, the complex and chaotic interaction of the fault energy with the wildfire fuel bed (with its own unique combustion properties that are highly dependent on the type of fuel and environment), sometimes through intermediary fuel materials that might also be combustible. This situation makes it extremely difficult to create formulas for fire risk as a function of the I^2t*R energy of a fault. Intermediary materials, for example aluminum particles from overhead arcing conductors, can ignite at the fault location and burn as they fall to the ground, contributing their own combustion energy to the wildfire fuel bed. The following sections discuss examples of various approaches that have been taken in the industry to determine the fire risk associated with these two basic fault types: direct contact faults and overhead-arcing faults.

3.2 Direct Contact Faults

Examples of staged fault testing in the industry have revealed the fire risk profile of direct contact faults under a specific set of severe but realistic fuel bed conditions over a range of low fault current levels. Tests were performed by drawing apart two energized mild steel electrodes, putting the resultant arc in direct contact with a dry mixed hay and straw fuel bed. The probability curves developed from the results of this staged fault testing are shown in Figure 3.2 below for 4.2 A, 50 A, and 200 A fault current levels. As fault current increases, the probability curves shift to the left, requiring faster tripping times to maintain similar probabilities of ignition. A possible conclusion from this graph is that there is a limit to the effectiveness that the speed of a protection system can have on maintaining a low probability of sustained fire ignition for faults in direct contact with a dry fuel bed. Figure 3.2 shows by testing that fire ignition risk does not follow the formula I^2t*R. This forces a look at methods that limit fault current to achieve this goal.



Ignition probability (Pr) against arc duration for 4.2, 50, and 200 amp arcs at 45°C and 10 km/H wind speed for hay/straw at 5% moisture.

Figure 3.2. Ignition Probability.[4]

3.3 Overhead Arcing Faults (Clashing Conductors)

One approach to quantifying the fire risk associated with overhead arcing faults is to use high-speed infrared cameras and software analysis to track the number of particles above a given temperature threshold over a range of distance from the point of the fault to ground. An immediate feature of overhead arcing faults that was revealed by this testing is the degree to which conductor geometry has an impact on hot particle production, with a pigtail configuration (broken or cut end of a conductor) producing significantly more (in some tests two orders of magnitudes or more) hot particles than the case of parallel conductors (smooth surfaces) arcing across each other. The consequence is that the concentration of the electric field at sharp points of conductors draws an arc to that single point, creating an avalanche of hot particles at that single location, as opposed to smooth conductor surfaces that allow the arc to traverse the surface, constantly moving to new cooler locations on the conductor. For the subset of faults conducted in this experiment (21 kV line-to-line faults ranging from 1,000 to 7,000 amps), the magnetic forces that act to push the arc away from the current source result in the arc traveling along the line in the case of parallel conductors. In contrast, for pigtail conductors, these magnetic forces are not sufficient to overcome the permanent establishment of the arc. The tendency is for an arc to travel along smooth parallel conductors, away from the strongest source of current, until it finds a sharp point where it can become fixed in place, and this produces significantly more hot particles.

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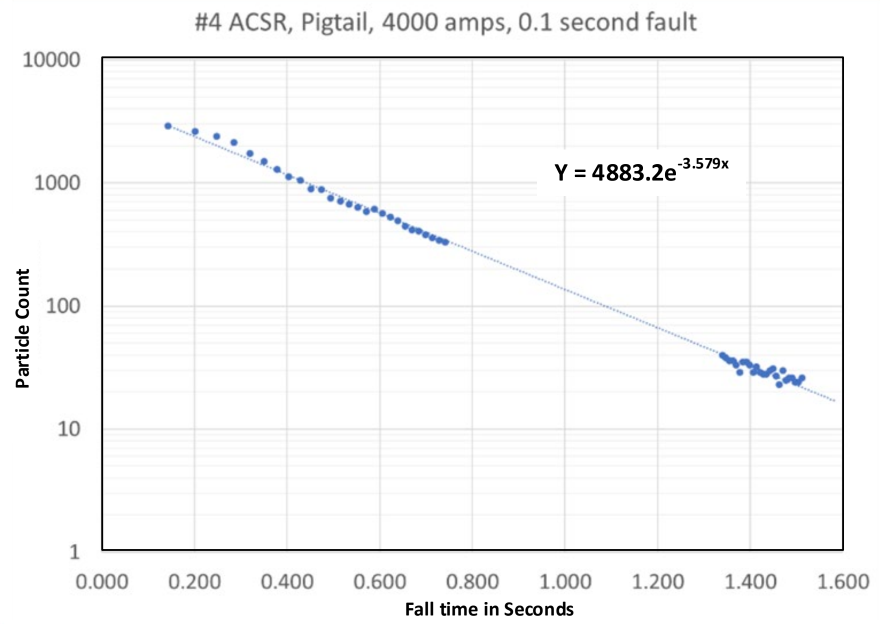
[4] Probability of Bushfire Ignition from Electric Arc Faults; https://www.researchgate.net/publication/283486798_Probability_of_Bushfire_Ignition_from_Electric_Arc_Faults

Figure 3.3 below shows a plot of the particle count and corresponding regression line for an overhead fault with #4 ACSR conductor in a pigtail configuration. This 4,000 A fault was interrupted after 0.1 seconds, and when the number of particles is graphed on a semi-logarithmic scale as a function of the fall time, a clear linear trend is observed.



Particle Count vs. Fall Time (seconds) for the Cage and Lift tests combined, 0.1 second fault time, for #4 ACSR, Pigtail Configuration.

Figure 3.3. Particle Count.[5]

Empirical equations were developed for additional conductor types and conductor configurations, with the equation being of the form $A(f) = e^{-\tau(f)t}$. These equations, derived from single staged fault tests and under a very limited range of fault interrupt times (less than or equal to 1 second), fall times (corresponding to 40 ft), and current values (around 4 kA), compute a predicted particle count as functions ($A(f)$ and $\tau(f)$) of fault interrupt time (f), and particle fall time (t).[6]

$A(f) = e^{-\tau(f)t}$ is an empirically derived equation for the number of particles having temperatures greater than 210 °C as produced by overhead arcing faults. $A(f)$ and $\tau(f)$ are both functions of the fault interrupt time (f); where $A(f)$ is the particle count, $-\tau(f)$ is the fault interrupt time, and t is the particle fall time.

Although these particle numbers do not directly translate to a fire ignition risk given the complex and chaotic nature of fire ignitions, these values indicate a relative fire risk for a given fuel bed from the numbers provided by such equations. For example, staged fault testing performed using a California Department of Forestry and Fire Protection approved fuel bed (dried grass) demonstrated that particle numbers greater than 10 resulted in a high fire risk, with numbers less than 5 resulting in a relatively low fire risk.

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[5] “Assessment of Hot and Flaming Particles and Fire Risk from High Current Faults”, Western Protective Relaying Conference 2022

[6] “An Assessment of Particle Production Hazard as a Function of Fault Time, Line Amperage, Conductor Configuration, and Conductor Type”, Western Protective Relaying Conference 2022.

3.4 Covered Conductor

For medium voltage distribution systems, covered conductors are those overhead conductors that have an external sheath mostly made of high density or cross-linked polyethylene (HDPE or XLPE respectively). The newer designs of the sheath can have as many as three layers, with the inner layer consisting of a semiconducting material to equalize the electric field and minimize voltage stress. When covered conductors were first applied in the 1970s, the main purpose was to reduce power supply outages due to vegetation touching bare overhead power conductors. Thus, these conductors are also called tree wires.

The use of covered conductors has proven to be an effective way to avoid many fault events on distribution systems as compared to using bare conductors. These events include phase-to-phase or phase-to-ground faults from a variety of conditions such as conductor sagging, conductor clashing due to wind or fault induced conductor motion, vegetation contacts, animal contacts, vehicle contacts with poles, and electrical contacts of man-made objects like balloons and kites.[7] Because of these benefits, many utilities around the world use covered conductors to improve their distribution service reliability and have received noticeable results.

As wildfire risks continue to grow, utilities in wildfire-prone regions have increasingly turned to covered conductors as a key strategy for reducing these ignition risks. However, the use of covered conductors may initially reduce the risk but will not eliminate the risk of wildfire ignitions. Other methods described in this report can be used in parallel with covered conductors to help reduce the overall risk of ignition.

One of the downsides of covered conductors is the lack of movement of the arc (motoring effect or arcing mobility) for flashovers caused by lightning strikes. If the length of the sheath is stripped to attach covered conductors to insulators, or the sheath cracks or has pinholes from conductor aging or foreign object brushing, the energy from lightning strikes tends to concentrate in these small areas of covered conductors and makes them more likely to break. If a covered conductor breaks and falls on the ground, the ground fault current can be much smaller than that of downed bare conductor. It is more likely for downed covered conductors to create a high-impedance fault situation than downed bare conductors. In fact, Pennsylvania Power and Light (PP&L) conducted staged fault tests in the early 1970s because "difficulty has been encountered in detecting and clearing faults resulting from XLPE covered aluminum overhead distribution conductors lying on the ground".[8] At the same time, the downed covered conductor sheath can insulate the conductor from arcing to receptive fuels along the conductor length limiting the ignition risk to the exposed bare conductor area.

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[7] "Effectiveness of Covered Conductors: Failure Mode Identification and Literature Review", Exponent Inc. 2020. https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=52749&shareable=true

[8] PP&L – Report of Distribution Conductor Staged Fault Tests held on October3-4, 1973 – Internal Report.

3.5 Industry Need to Define the Risk of Ignition

The electrical grid spans thousands of kilometers throughout the forest and creates millions of ignition possibilities. Each point of the arc and/or contact with fuel can present very different risk characteristics and the discussions above describe some initial testing and provide a framework of understanding of the major risks of wildfire ignition.

Some large data sets of wildfire ignitions from North American utilities show that wildfire ignition can occur in a variety of conditions with the most common being:

- by direct contact with the energized equipment (i.e. lines) with combustible material
- by overhead arcing of energized equipment causing molten particles to fall on combustible material (i.e. conductor slapping).

However, there are many factors and variables involved in determining the risk of ignition. Examples include the amount of electrical energy present (fault level and arc), fuel condition (moisture content) and weather (temperature, humidity, and wind speed). The testing required is generally more than a single entity can perform and there is a need for the industry to collaborate in this effort. The challenge to the industry is to determine the risk of ignition for various factors.

4. FAULT RESPONSIVE RELAY APPLICATIONS

The first thing to note when considering the practices of protective relaying is that every utility is different. The environment, philosophies, geography, weather patterns, politics, and economical situations are all different. For over 100 years the grid has used overcurrent and impedance-based methods to detect and isolate the fault on a line. This effort began with simple overcurrent protection devices and evolved to include impedance-based devices, communications-assisted schemes, differential protection, traveling wave (TW) applications, and sensor-based methods. This section provides a discussion and explores the benefits and risks involved in the application of each method.

Protection of the electrical grid focuses on the isolation of faults or damaged elements with as little interruption to the rest of grid as possible. This requires coordination of protective relays and schemes from the source (upstream) to the load (downstream). The characteristics of the grid allowed time delayed and instantaneous tripping characteristics to be “coordinated” on the transmission and distribution lines. The objective is to clear all faults as fast as possible and quicker than the next line or power system element (i.e. breaker, bus, transformer) that is closer to the source (i.e. generator, transformer, etc.), thereby reducing the amount of the grid and customers that need to be deenergized during isolation of the fault.

To achieve coordination some faults are cleared immediately (instantaneous or with no deliberate delay) and some faults are cleared with an intentional time delay. As discussed above, the longer the fault or arc lasts the more heat energy is present and the greater risk of a wildfire. This section shares these methods with the industry to educate and inspire new and better ways to reduce the risk of wildfire ignition by the utility systems.

4.1 Distributed Energy Resources on the Distribution System

The distribution grid is changing from a predominantly radial system that originates from one source to a system with bi-directional power flow. This is due to the installation of distributed energy resources (DER) throughout the distribution system at an accelerated rate. This is largely driven by the installation of inverter-based resources (IBR) such as solar, wind, batteries, and other renewable sources. However, DER may also include more traditional generation such as synchronous or induction machines. Typically, IBRs contribute much less fault current than what is usually provided by the utility or from traditional rotating generation. This could compromise the fault detection time and the time to de-energize a feeder or line with IBRs. With less fault current, overcurrent relaying will operate with a greater time delay or not at all if the fault current is below the sensing level of the relaying. The IBR owner deploys protection that could disconnect the IBR for "loss of source" and in some instances this will trip the IBR output after a time delay. These conditions can lead to increased tripping time and an increase in the risk of wildfire ignition, even after the utility source has been disconnected. The technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems and DER is covered in IEEE 1547.[9]

Fault protection applications on distribution systems are also changing and some of these new schemes are referenced in this report such as distribution line differential (DLD) schemes and sensor-based schemes. These schemes detect the disturbance and provide a trip signal that can be used at the utility substation or the DER. If the DER is left connected to the faulted line, there may still be energy flow, and an increased risk of wildfire ignition could be present. This report does not address this risk, and more study is needed to quantify the DER risk.

4.2 3-Wire and 4-Wire Systems

This report discusses various mitigations that can be applied to the neutral of a transformer to reduce the amount of fault current and energy at the fault or where the arc might contact dry fuel. It is important to note that electric grids, including distribution systems, are not constructed the same. The North American grids have evolved to be primarily 4-wire multi-grounded, and the European, Asian, Australian, and African grids are primarily 3-wire uni-grounded (including isolated and compensated neutrals). There are other less common configurations as described in Section 6. Each system evolved for different reasons and the mitigations used to reduce the amount of current flow for a ground fault will also be different.

The neutral conductor connected at the transformer of 4-wire multi-grounded systems allows zero sequence current to flow for ground faults (refer to Figure 4.2A). On 3-wire uni-grounded systems there is no neutral conductor, and the ground fault current must flow through the earth back to the transformer (refer to Figure 4.2B). Sections 6 and 7 provide various neutral and system grounding techniques used on various types of systems.

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[9] IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces; IEEE SA - IEEE 1547-2018, https://standards.ieee.org/ieee/1547/5915/

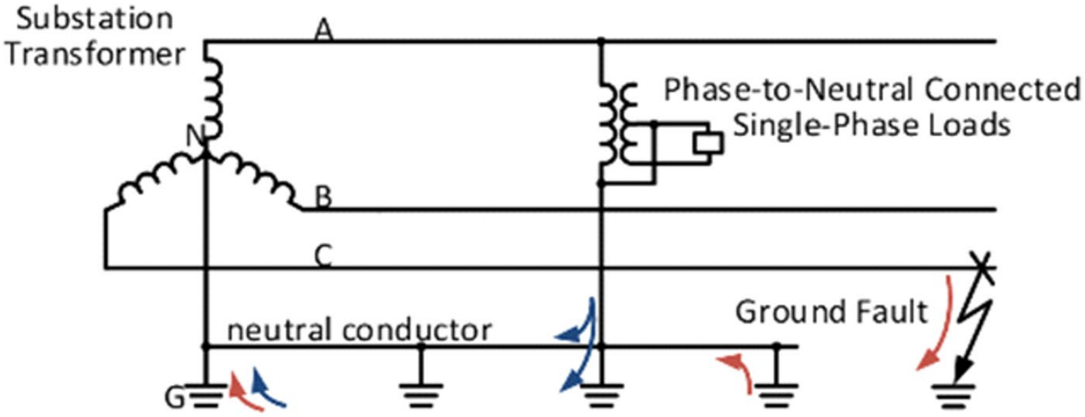

Figure 4.2A Typical 4-wire multi-grounded system.

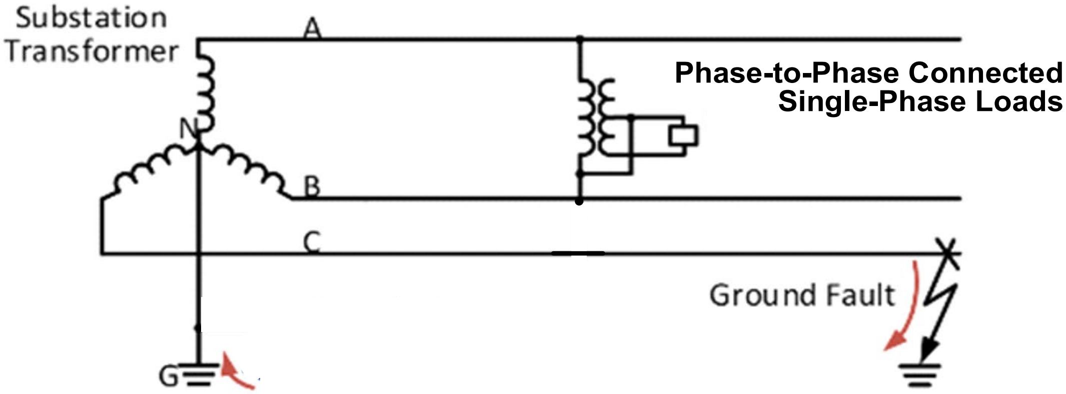

Figure 4.2B Typical 3-wire uni-grounded system.

4.3 Relay Setting Change Methods

This section presents practices and methods, presently in use to achieve faster tripping times, when changing relay settings for wildfire risk reduction. The methods presented in this section may work for some utilities but might not be applicable for others. Protection engineers must always consider the system parameters and the utility circumstances before implementing changes in protection philosophy or practices. Some utilities apply sophisticated fire risk modeling and may have high fire risk areas determined by government entities that guide the application of these fast trip settings.

It may be desirable for a utility to modify or have predetermined alternate settings that can be deployed at will during fire season or during dry periods, where chances of ignition are heightened. Because there is no single solution that will provide the panacea for wildfire mitigation, utilities often take a layered approach and may use a combination of the following techniques to develop a tailored protection method geared toward reducing the risk of ignitions caused by the power system equipment or operation.

4.3.1 Increase Relay Sensitivity and Trip Time Modifications

Relay coordination with downstream relays can mean that there are intentional time delays introduced to provide selectivity and allow the downstream relays to operate prior to the upstream relays (upstream relays are closer to the utility/grid/source). Faster tripping means less energy at the arc with the objective of reducing the risk of ignition. One option is to increase the sensitivity of the relay settings (overcurrent and impedance-based relays) so that faster tripping is realized over the entire line (even to the end of the line for distribution feeders). Another option is to change the trip delay for overcurrent protection where the time curve or definite time settings influence the tripping speed. This often compromises coordination and will cause the loss of more customers than if relay coordination is maintained. This is accomplished by decreasing the setpoint (pickup value) of the overcurrent setting or increasing the overreach of an impedance relay and/or decreasing the trip time of the operating elements. The relays have some inherent inaccuracies based on margins of voltage and current sources and the sensitive settings will be made to overreach the remote terminal.

In some cases, utilities may decide to install interrupting devices with relays on the feeders to create selectivity for faults. The relay instantaneous elements at the substation and the downstream recloser could be coordinated where faults closer to the end of the feeder could be detected by the instantaneous element at the recloser and not by the instantaneous element in the substation and respectively open the recloser and not the breaker at the substation. This preserves all the customers upstream of the recloser.

The action of increasing the sensitivity of the relay or reducing the trip time can be programmed into SCADA thus giving the entity the ability to change the sensitivity remotely from an Operations Center. The relay would have to have multiple settings capability.

Another method that is available is referred to as Zone 1 Extension. This method will automatically extend the normally underreaching Zone 1 elements to overreach the remote terminal(s). Consequently, this provides instantaneous clearing for all faults on the transmission line. However, as discussed above, it can result in a lack of relay coordination for some faults and cause the loss of more of the system than necessary or more customers than desired.

Utilities may choose to initiate these setting changes to reduce the risk of wildfires. In at least one study performed by Haas for the University of California Berkeley “fast trip settings” were declared the most cost-effective method to reduce the risk of wildfires (of the methods studied).[10] They may initiate the settings when the environmental conditions exist (i.e., dry fuel, low humidity, hot days, and wind), or when a regulatory agency or political body indicates that utilities must take action to limit the risk of wildfire ignition.

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[10] Risk-Cost Tradeoffs in Power Sector Wildfire Prevention, Energy Institute at HAAS, WP 347, Cody Warner, Duncan Callaway, and Meredith Fowlie February 2024; https://haas.berkeley.edu/wp-content/uploads/WP347.pdf

4.3.2 Fuse Saving and Fuse Blowing Coordination

The protection deployed on distribution systems can include the substation circuit breaker, reclosers, and fuses. These devices are coordinated based on how they detect a fault with the substation circuit breaker operating last and usually with a time delay to allow the downstream devices (reclosers and fuses) to operate first.

In general, fuses operate and can isolate faults faster than circuit breakers and reclosers and therefore reduce the energy available for ignition. However, when fuses operate the element inside the fuse will burn and melt open and, in some situations based on fuse design, could expel hot material, that could ignite fuel and start a fire. For this reason, the entity must consider the risk in allowing the operation of expulsion fuses. Some fuse designs expel fewer hot particles and may have been tested for spark emission to various regional or national standards such as AS1033.1-1990.[11]

Circuit breakers and reclosers can operate multiple times, but fuses can only operate once and must be manually replaced. For this reason, utilities will generally try to "save" the fuse from operating (sometimes referred to as "blowing") for temporary faults by operating the recloser or substation circuit breaker first to allow a transient fault to clear before the fuse operates. This is called a fuse-saving strategy.

In a fuse-blowing scheme a fault beyond a fuse is intended to be isolated by the fuse without an operation of upstream circuit breakers or reclosers. Fuse operating characteristics are chosen based on the philosophy that is deployed. During times of wildfire risk, automatic reclosing can be turned off and entities can purposely allow the circuit breaker and/or recloser on the line to operate faster than the fuse and thus save the fuse.

4.3.3 Automatic Reclosing

Reclosing is the manual or automatic closing of a circuit breaker or recloser after it has been opened by protective relaying. This is done to restore the system as quickly as possible and maintain electric system reliability. Utilities have implemented many different automatic reclosing schemes that deploy various time delays for the reclose and could deploy multiple reclose attempts. If the original fault condition is still present after the reclose, then the protective relays will trip the circuit breaker or recloser, or the fuses will operate if a fuse-saving scheme is implemented.

The reclosing of the circuit breaker will reenergize the line and if a fault remains, it will provide energy for the arc. This can produce additional risk of a wildfire if the environmental condition exists, and fuel is present at the arc. Automatic reclosing can also introduce the possibility of fault induced conductor slap that could create arcing and hot particles. During increased ignition risk conditions, utilities may disable automatic reclosing to mitigate closing into a faulted conductor that is in contact with the ground or other medium that could ignite the fuel.

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[11] Australia Standard Australian Standard® AS1033.1-1990, High voltage fuses (for rated voltages exceeding 1000 V) – Part 1: Expulsion Type, Standards Association of Australia, Homebush, NSW."

The entity must also consider the risk of an automatic reclose of the circuit breaker or recloser or even what a manual close would present. One strategy would be to disable the automatic reclosing and patrol the line prior to closing the recloser or circuit breaker.

Dynamic Automatic Reclose Adjustments

Many wildfire mitigation schemes disable the automatic reclosing function to the high fire risk area during adverse weather conditions. By disabling reclosing, utilities are choosing to impact electric service reliability and are prioritizing wildfire risk reduction. In cases where part of a line passes through a high fire risk area, the reliability of the entire feeder can be affected. A fault transmitter and receiver sensor system can provide high-speed fault detection information directly to a recloser control. The fault transmitter detects fault current and sends a wireless indication to the fault receiver, which communicates directly with the recloser control via a high-speed communications link. The sensor systems are optimized for speed and typically provide fault indications to the recloser control within a few milliseconds of the fault inception. This is sufficiently fast to dynamically change the reclosing or protection system of the recloser control based on where the fault occurs on the system.

By placing fault transmitter sensors at laterals or the boundaries of high fire risk areas, utilities can enable reclosing for faults that occur outside these areas, as shown in Figure 4.3.3. This sensor setup makes it possible for utilities to focus on wildfire risk reduction benefits of blocking reclosing while retaining system reliability for faults in areas where the fire risk is low.

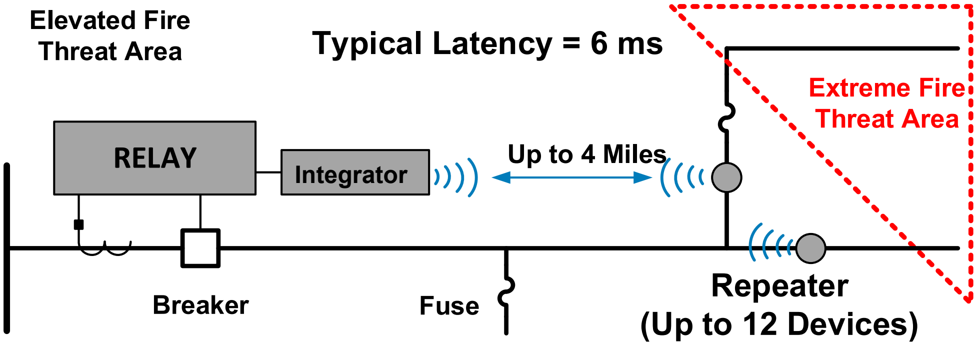

Figure 4.3.3 Dynamic Reclosing Application.

4.3.4 Impedance-Based Protection in Distribution Systems

Impedance-based protection (also called distance protection) is commonly used on transmission and sub-transmission systems and is much less common on distribution systems. Distance protection as compared to overcurrent protection can distinguish fault impedance from load impedance. Impedance-based protection will be limited by load, with ground distance protection limited by phase unbalance. Given that distribution systems have many branches and tapped lines, greater care is taken when applying this type of protection on distribution systems.

Because sensitivity is a concern in wildfire areas, the fault detectors (impedance based or other) are set to maximum reach (sensitivity), assuming loading and unbalance can be accounted for. Specific setting groups for use during high-risk days can be utilized that maximize reach but may compromise fuse coordination. Backup overcurrent protection can provide resistive fault coverage, especially for ground faults. Additional value could be achieved when impedance-based protection is combined with communications-assisted protection. Some other considerations are listed below:

- Impedance-based protection may be applied to avoid delayed clearing with multiple and series overcurrent protection devices, and/or where selective protective zones are required.
- Quadrilateral impedance-based protection characteristics can be applied to cover resistive faults or load encroachment.
- Load encroachment blinders may be used to extend the reach of the phase distance protection and prevent misoperation due to load.
- Resistive fault coverage is very limited when the system X/R ratio is low, where smaller conductors, or highly resistive faults are a concern.
- Phase-to-phase connected transformers, depending on core type, may provide a source of infeed, potentially limiting the ground distance element's reach.
- DER provides a source of infeed and may affect the distance element reach.
- IBRs can impact directionality, depending upon the characteristics of the inverter controller.
- Coordination can be a challenge and "stacking" overcurrent relaying may result in extended clearing times.

Utilizing impedance-based protection in distribution systems can be applied with due attention because of configuration of the lines that could include reconfiguration and looped networks. Distribution systems were designed with fuses and can be switched to alternate configurations.[12] The value of impedance-based protection on distribution systems in wildfire areas comes from its speed and as mentioned above, its ability to distinguish fault impedance from load impedance.[13]

4.4 Communications-Assisted Protection Methods

Communications-assisted protection systems provide a way to detect a fault on a line faster than traditional time delayed coordinated tripping. However, there is a significant difference between fault detection on the transmission and distribution systems. The transmission system is constructed to deliver bulk power from the sources (i.e. generation) to delivery points on the distribution system. The distribution system then delivers the power to thousands of loads across the grid. The distribution system is commonly a radial system (also open loops) with the sources being a substation and multiple feeders that

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[12] C. Holt, R. Patterson, A. Saad, "Arc Resistance Coverage and Mho Expansion - The Devil is in the Details", WPRC in 2018, https://relayman.org/papers/ArcResistanceCoverageMhoExpansion.pdf .

[13] E. Liu and N.-K.C. Nair " Line-to-Ground Arc Flash Fault Detection Using Distance Protection Scheme for Wildfire" 2024 IEEE PES Innovative Smart Grid Technologies - Asia (ISGT Asia), Bangalore, India, 2024.

distribute the power and may have many tap points and laterals to the loads (see also the discussion in Section 4.1 about DER on the distribution system). The transmission system is generally less complex in topography, not radial, and the lines are connected from one substation to another with interrupting devices (i.e. circuit breakers at all terminals).

The configuration of the transmission system allows for communication signals to be used to connect all terminals and share relay information about fault detection. The distribution systems' radial nature and hundreds of connections with reclosers and fuses do not easily allow for communications to be used between all terminals. Over the last decade, expanded cell coverage with ever-increasing speed has provided a method of communicating to more equipment (sensors and relays installed in the system outside of the substation). This report provides information on these emerging, advanced schemes (See Section 4.4.3 Distribution Line Differential Methods, and Section 5.2 Sensor Based Methods).

When a communications channel is available, the clearing time of line faults can be significantly reduced. The intentional delays built into protection systems are necessary to achieve coordination with downstream protection. However, when the protective relays at both ends of a transmission line can communicate, the fault can quickly be determined to be an internal (in section) fault, and both ends can trip their respective circuit breakers without significant delay. The schemes summarized below are fully described in IEEE C37.113 Guide for Protective Relay Applications to Transmission Lines.[14]

Utilities may apply communications-assisted protection to achieve an adequate level of reliability and choose a particular scheme for various reasons to take advantage of communication types and availability, relay vintage, infrastructure, and topography. Not all transmission lines are covered by communications-assisted protection and typically this was driven by reliability. However, communications-assisted protection typically provides faster detection over the entire transmission line and can isolate the fault quicker than time delayed tripping, thereby reducing the energy available at the arc.

4.4.1 Directional Pilot Schemes

Directional pilot schemes use communications from each end of the line to provide fault detection over the entire line. Various schemes are described in this section and are covered in more detail in the IEEE C37.113 Guide for Protective Relay Applications to Transmission Lines.[14] Utilities apply a particular scheme based on internal requirements that could involve reliability needs, existing infrastructure, and the topography of the system.

Figure 4.4.1 shows a transmission line with relays at each end. This drawing provides a simple depiction of the communications that occur between the two ends of a transmission line and will be referenced in the following discussions. There are many different configurations across the grid. The concept here is to find methods and applications to provide fault detection over the entire line and trip as fast as possible.

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[14] "IEEE Guide for Protective Relay Applications to Transmission Lines," in IEEE Std C37.113-2015 (Revision of IEEE Std C37.113-1999) , vol., no., pp.1-141, 30 June 2016, doi: 10.1109/IEEESTD.2016.7502047.

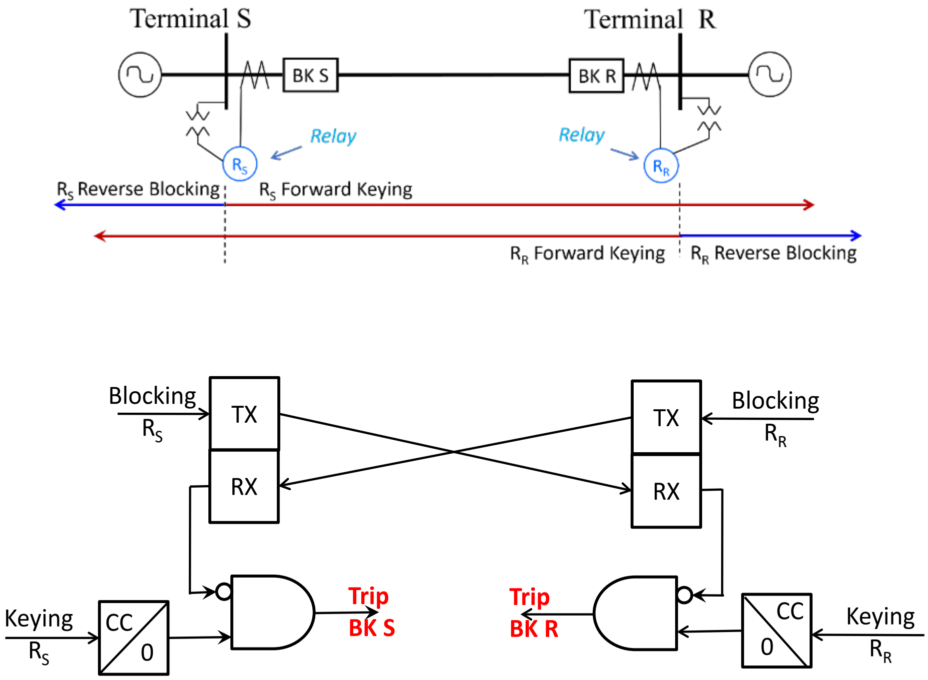

Figure 4.4.1. Simplified Directional Pilot Scheme (DCB).

There are various versions of directional pilot schemes and utilities will choose these schemes based on infrastructure, needs, and internal preferences. Some utilities have developed a particular scheme based on internal knowledge and standards. Some schemes implemented are the following:

- Directional Comparison Blocking (DCB)
- Permissive Overreaching Transfer Trip (POTT)
- Permissive Under-Reaching Transfer Trip (PUTT)
- Direct Under-Reaching Transfer Trip (DUTT)
- Directional Comparison Unblocking (DCUB)

These schemes provide fault detection over the entire transmission line and typically provide faster clearing for all faults on the transmission line. These schemes are covered in more detail in the IEEE C37.113 Guide for Protective Relay Applications to Transmission Lines.

4.4.2 Transmission Line Current Differential Protection

Line Current Differential (LCD) is a relay scheme that collects information about the current from each terminal (source or load) of a transmission line to determine if there is fault or phase imbalance greater than the pickup value of the differential. These schemes are usually able to detect a problem within a few cycles and initiate the opening of the circuit breakers on all terminals of the line thus de-energizing the fault. LCD schemes are typically very fast and very sensitive.

This scheme may be used when the communications channel is sufficiently robust to handle the constant traffic required for each end to communicate measured current values to the other. As such it is typically implemented over fiber optic or dedicated radio channels that have a performance of 56 kbps or better. The relays at the ends of the transmission line (2, 3, or 4 terminals in some cases) transmit current data to each other and implement differential protection. This bi-directional data flow is shown in Figure 4.4.2.

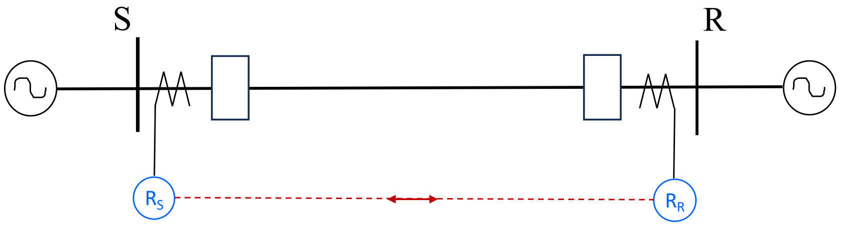

Figure 4.4.2. Line Current Differential.

Line current differential protection uses phase currents and may use negative- and zero-sequence currents. Digital data can be transmitted, allowing one relay to command the others to trip if it determines a fault to be internal to the protected line. The issues of channel delay, latency, and data alignment are all handled well by digital line current differential relays. The basic operation of the scheme is the simple differential method and is fully described in an IEEE Guide[15] that is summarized in a relay conference paper[16].

4.4.3 Distribution Line Differential Protection

Traditional protection of sub-transmission and distribution networks were historically limited by the type and location of commonly applied protective relays and interrupting devices (circuit breakers, reclosers, fuses, etc.). Time-coordinated overcurrent or distance relays located in the substation and at line reclosers have an expected limitation in terms of sensitivity and fault-clearing time.

The addition of interrupting devices can dramatically improve distribution and sub-transmission protection. These devices will sectionalize a complex distribution feeder system into smaller and simpler protection zones by adding circuit breakers, relays, reclosers, and current and voltage transformers (CTs and VTs).

A solution in the form of multizone differential protection can be deployed for protecting distribution and sub-transmission networks with speed and sensitivity that reduces the wildfire risk. It can be prohibitively expensive if it is assuming the traditional approach of adding de-facto substations, interrupting devices, and wire wound CTs and VTs. This is illustrated in Figure 4.4.3.

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[15] "IEEE Guide for Application of Digital Line Current Differential Relays Using Digital Communication," in IEEE Std C37.243-2015, vol., no., pp.1-72, 7 Aug. 2015, doi: 10.1109/IEEESTD.2015.7181615.

[16] B. Mackie and C. Palmer, "Summary paper for C37.243 IEEE Guide for Application of Digital Line Current Differential Relays Using Digital Communication," 2017 70th Annual Conference for Protective Relay Engineers (CPRE), 2017, pp. 1-8, doi: 10.1109/CPRE.2017.8090049.

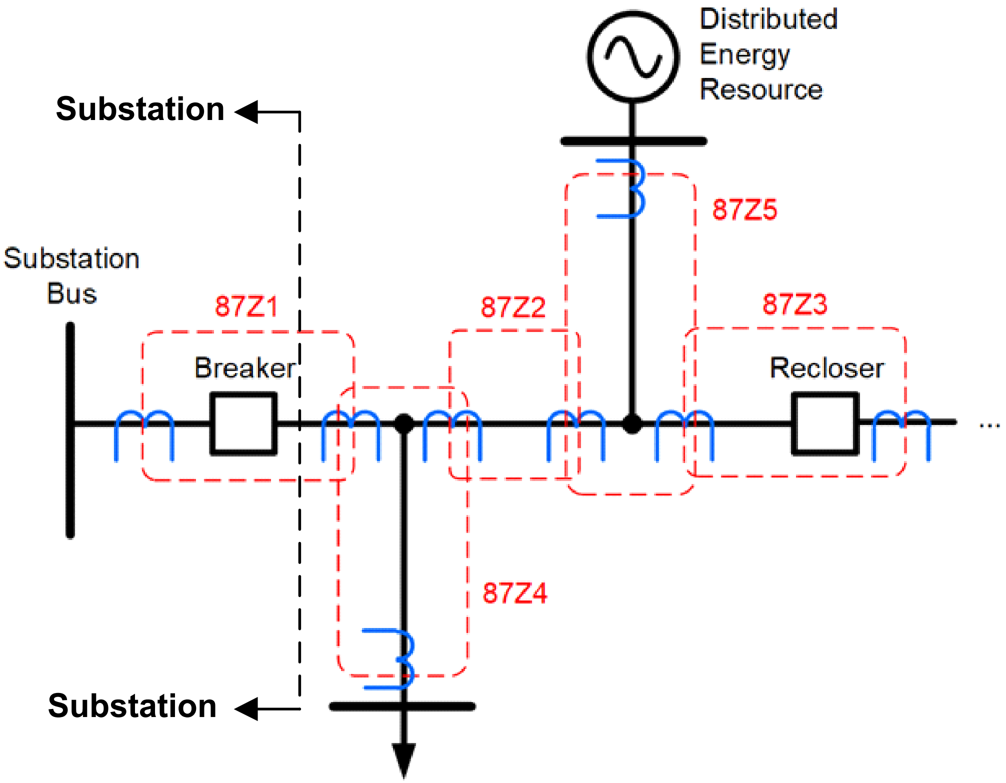

Figure 4.4.3. Multiple differential zones on a distribution system.

Feeder protection based on the differential principle replaces time coordination as a primary protection principle for the feeder. Feeder faults can be cleared without a time delay (in milliseconds instead of in hundreds of milliseconds or seconds), dramatically reducing the fault energy.

4.4.4 Passive Distributed Measurements

One approach to solving distribution protection challenges is to deploy passive distributed measurements to the feeder system.[17] These can be configured to provide the differential protection(s) illustrated in Figure 4.4.4. This application can achieve the selectivity and speed discussed above without the cost and complexity of adding interrupting devices (i.e. circuit breakers or reclosers) or CTs and VTs along the feeder.

Passive distributed voltage and current measurement systems (instrument transformers or sensors) are mounted directly on poles or crossarms, at strategic locations along the distribution feeder (refer to Figure 4.4.4) and are connected via single-mode fiber (which may also provide a communication network that enables high-speed information flow). If these measurements have very low latency (a few milliseconds or less) and high resolution, and can have measurement outputs interfaced to protective relays, then the protection of

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[17] M. Mohemmed, P. Orr, S. Blair, N. Gordon, I. Mckeeman, A. Mohamed, and A. Bonetti, “Differential Protection of Multi-Ended Transmission Circuits Using Passive, Time-Synchronised Distributed Sensors,” proceedings of the PAC World Conference, Prague, Czech Republic, 2022.

the feeder can be improved with multizone differential protection.[18] A single dark fiber in all-dielectric self-supporting (ADSS) fiber optic cable is well suited to this application.

The passive instrument transformers and fiber optic interfaces have no active electronics and no power supply or energy harvesting at the remote installation site. The underlying technologies that allow this passive application can be based on Bragg effect encoding of electrical signals from traditional CTs and VTs or on remotely interrogated optical instrument transformers.[19] [20]

Dozens of instrument transformers, using passive interfaces, can be daisy-chained on the same single-mode fiber. These systems differ in terms of the underlying technology but share the following characteristics (refer to Figure 4.4.4). The information can be received at the substation, for all local and remote CTs, and made available to protective relays through IEC 61850-9-2 Sampled Values (SV). The protective relays in the substation provide all the required protection functions (multizone differential, time-overcurrent backup, and multi-ended fault locating).

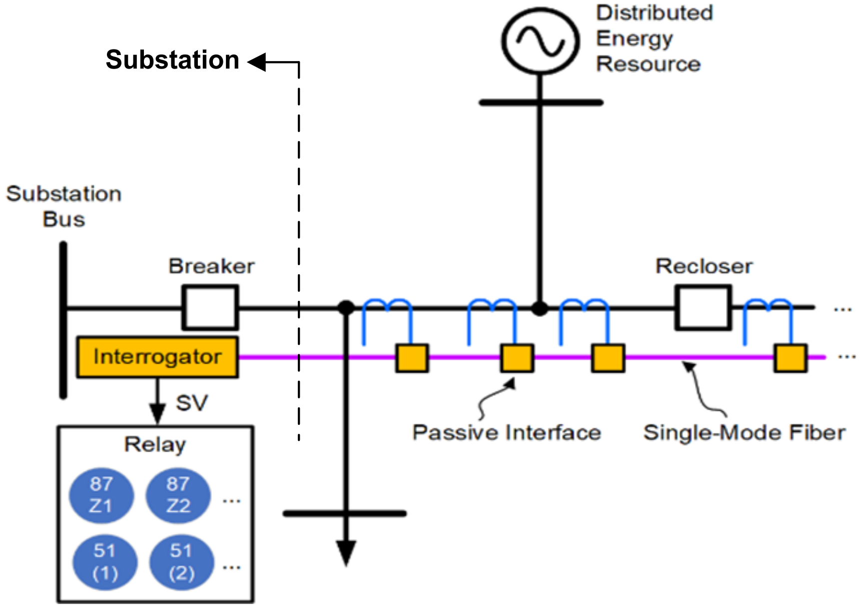

Figure 4.4.4. Passive distributed measurement system.

Differential protection based on passive distributed measurements can provide the detection of high-impedance faults with several orders of magnitude better sensitivity and speed as compared to traditional approaches of time coordinated protection. It also can provide detection of, and tripping for, broken-conductor conditions before the conductor becomes a downed conductor.

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[18] B. Kasztenny, S. Blair, N. Gordon, P. Orr, and C. D. Booth, “Solving Complex Feeder Protection Challenges and Reducing Wildfire Risks with Remote Measurements,” proceedings of the 50th Annual Western Protective Relay Conference, Spokane, WA, USA, 2023.

[19] P. Orr, G. Fusiek, P. Niewczas, C. D. Booth, A. Dyśko, F. Kawano, T. Nishida, and P. Beaumont, “Distributed Photonic Instrumentation for Power System Protection and Control,” in IEEE Transactions on Instrumentation and Measurement, vol. 64, no. 1, 2015, pp. 19–26.

[20] J. Bengoechea, T. Sarto, J. Neimann-Larsen, “Optical System for Underground Cable Maintenance, Mixed Lines Fault Discrimination and Underground Cable Fault Location,” proceedings of the 10th International Conference on Insulated Power Cables, Paris – Versailles, France, 2019.

4.4.5 Time-domain and Traveling Wave Protection

Time-domain line protection schemes have been gaining attention in recent years. Time-domain protection does not rely on voltage and current phasors at system frequency as in phasor-based protections. It uses time samples of voltages and currents and operates during the transients of system disturbances. Therefore, time-domain protection has the advantage of operating speed and can issue a trip signal to open circuit breakers in the range of 1 millisecond or faster.[21]

Traveling wave (TW) fault location is a well-established technique for accurate fault location on the transmission system. TW techniques are less common on the distribution system due to the complexity of the TW reflections. Relays of this type have megahertz sampling rates and use signal processing to accurately detect the arrival of TWs when a fault occurs on a system. These types of relays are also called traveling-wave relays. When a fault occurs on a transmission line, the fast change in voltage and current at the location of the fault results in a transient wave traveling along the transmission line in both directions away from the fault. By comparing the times of arrival of these transient waves at the two terminals of the line (and knowing the length of the line), the relay can calculate the location of the fault.

TWs are also produced for non-fault related events. Examples include when a circuit breaker or disconnect is opened or closed, a conductor breaks, lines fall, a fuse operates, or even when vegetation contacts the line. For this reason, TW techniques are covered in Section 8.5.

5. HIGH-IMPEDANCE FAULT DETECTION

An energized conductor lying on the ground (a “downed” conductor) is a major source of wildfire ignition. While in contact with the ground, current flows through the air gap in quasi-conductive material that the downed conductor contacts, creating arcing. These materials, like concrete, bare earth, and wet vegetation, represent a high impedance to current flow, producing small arcing currents. These currents vary significantly during the arcing period. Arcing produces a wide spectrum of even-, odd-, and inter-harmonic energy along the power line that extends into the megahertz range. The arcing signal fluctuates in energy level and exhibits random changes over time, making it very difficult to detect. A downed conductor arcing on the ground is a typical example of a high-impedance fault (HIF).

Protective relays and other devices monitor the power-line high-frequency spectrum to detect HIFs. The algorithms in use have these elements:

- Current and voltage inputs from which the algorithm derives the high-frequency signal component
- A method to separate even-, odd-, and inter-harmonics of interest in the HIF spectrum. The extent of the frequency range is from sub-harmonic to 1 MHz

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[21] E. O. Schweitzer, III, B. Kasztenny, M. Mynam, A. Guzmán, and V. Skendzic, “New Time-Domain Line Protection Principles and Implementation”, https://selinc.com/api/download/113979/?lang=en

- A Fourier transform over a fixed time window, or a wavelet processing technique with a variable time window, to separate the signal into different components
- A reference or background average or total energy quantity that provides a stable, pre-fault reference
- Settings that tune the response of the detection algorithms. These include initial algorithm sensitivity and counter/confidence periods
- Decision logic to differentiate an HIF condition from other system conditions, such as switching operations and noisy loads

Most methods in use today have the following additional attributes:

- A means to classify/learn and subtract regular power-line noise events and other system conditions, thereby increasing security
- Security measures to enhance the reliability of the HIF decision. These include counters and confidence bins, usually arranged by spectrum harmonic component, and monitoring load rate of change to differentiate load events from arcing/bursting events
- Some implementations use statistical and wavelet analysis to extract the current-signal energy content, to improve fault-detection security
- Historical trending and memory
- Additional restraint and supervision for increasing reliability. These are second-harmonic supervision for transformer energization and voltage-sag monitoring to detect whether faults are on nearby lines
- Directional analysis to determine if the fault is upstream or downstream from the relay/device
- Some of the methods use a ground-current measurement for increased sensitivity.

5.1 Pulse Counting Methods

A certain percentage of high-impedance ground faults result in intermittent occurrence of fault currents. The fault current occurs and then reduces below detection levels or even disappears (the fault self-extinguishes). The fault then, typically, reoccurs and then self-extinguishes again, and the process repeats multiple times with irregular intervals (refer to Figure 5.1). This type of high-impedance fault is extremely difficult to detect with very low ground element settings and with typical high-impedance fault detection algorithms, due to the intermittent nature of the fault.

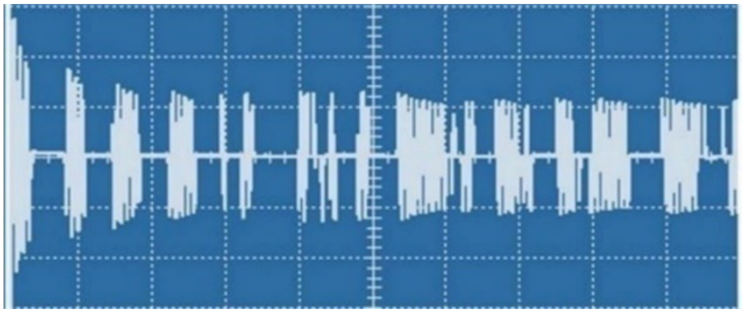

Figure 5.1 Example of intermittent and harmonic-rich HIF current waveform.

Some applications have been developed to apply a ground current spike or pulse counting algorithm which can be set to count the number of sudden increases in ground current over a set amount of time. Counting methods can be configured to alarm or trip for this irregular type of high-impedance ground fault. This approach is different than relying on electromechanical reset emulation to try to operate for these fault types.

There are several details to consider when applying this method to detect as many faults as possible while avoiding false positive indications. Consider the number of ground current pulses that might occur in a protection device on a feeder during load transfers or switching in/out of loads on a lateral, performed with single-blade switches. A similar effect can be observed with time delays between phases for gang-operated switches as well. To minimize false indication in these cases, logic can be developed to continuously monitor a time averaged ground current level and only count pulses that exceed a set amount of current (in amps) or percent above this time averaged value. This approach has the advantage of increasing sensitivity during light loading periods. Total harmonic distortion content can also be used to filter the current pulse counting methods to avoid false positive indications.

5.2 Sensor Based Methods

Due to the challenges of detecting high-impedance faults (HIFs) and the small fault-released energy that is needed to ignite wildfires, HIF detection and wildfire mitigation schemes can be implemented as a system approach, integrating information from relays, sensors, Advanced Metering Infrastructure (AMI), and other devices to increase the reliability of the fault detection and effectiveness of the mitigation scheme.

The sensors can be installed throughout the distribution and even the transmission systems. The communications strategies and mediums include a variety of advanced and traditional approaches that include direct connected fiberoptic cables, line-of-sight 900 MHz signals, cellular network connections, local area networks (LAN) and wide area networks (WAN), and satellite connections. The data can be streamed or polled and, in some situations, could be cloud based.

Positive detection and location of downed conductors

It can be beneficial to differentiate downed-conductor related HIFs from others like vegetation brushing an overhead conductor. A downed power conductor itself can be a severe public hazard in addition to the possibility of igniting wildfires. Some HIF detection algorithms sense a loss of load condition to relate the identified HIF as a downed conductor situation. However, depending on the location where the conductor is down, the load lost can be a fraction of the total feeder load. Therefore, it is not always reliable to detect the loss of load due to a downed conductor. One sensor application is to use fault/load transmitters (sensors) deployed at strategic locations of a feeder to detect a downed-conductor related loss of load condition more easily. This loss-of-load information can be sent to an HIF detection device (relay) to positively identify the fault as a downed-conductor event. With this information, the downed conductor can also be located at a specific lateral on a distribution feeder with many branches.

Figure 5.2 shows an example application. While the figure shows the situation that the fault/load transmitter (sensors) information is integrated to SCADA first before it is sent to the HIF detection device (relay), the relay can receive the information directly by installing the receiver at the fault detection location.

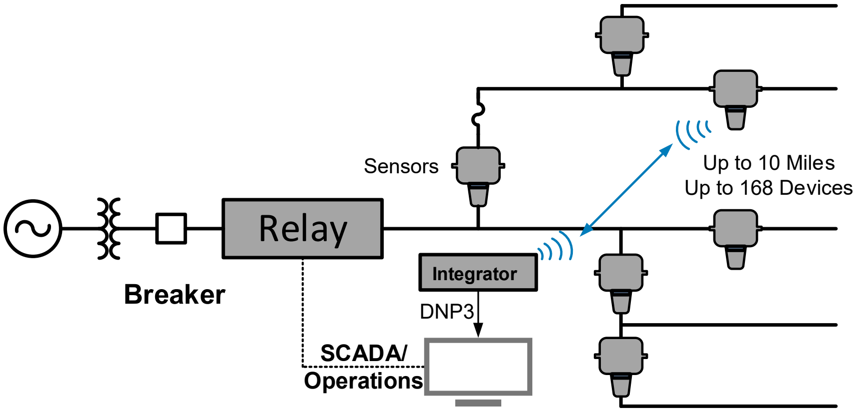

Figure 5.2 Example of Fault/Load Transmitter and Receiver Application.

6. NEUTRAL GROUNDING PRACTICES

When a ground fault occurs, the neutral grounding method dictates how much ground fault current and energy release will result and how system voltages will respond. It will impact the quality of electrical service to customers, selection of ground fault protection, fault location techniques, and operational complexity. It also impacts capital investment costs and lifetime operational expenditure.[22] [23]

As detailed in Section 3, fire ignition risk increases with an increase in fault energy. Fault energy is a function of the magnitude of the fault current and the duration of the fault. Neutral grounding methods can significantly reduce ground fault current levels and fire ignition risk and can result in ground fault currents being reduced from tens of thousands of amps to milliamps. When applying non-effective grounded systems (delta or high-impedance grounding methods) the effects of temporary overvoltage (TOV) on equipment and the impact on detecting ground faults must be considered. Various neutral grounding practices are discussed below.

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[22] IEEE Guide for Protective Relay Applications to Distribution Lines, IEEE C37.230-2020; https://standards.ieee.org/ieee/C37.230/5905/

[23] IEC Power installations exceeding 1 kV AC and 1,5 kV DC - Part 1: AC; IEC 61936-1:2021; https://webstore.iec.ch/en/publication/64490

6.1 4-Wire Multipoint Grounded Wye

Multipoint grounded wye 4-wire systems are prevalent for medium voltage circuits in North America and support phase-to-phase and phase-to-neutral connected loads. This can reduce equipment costs but typically results in high levels of ground fault current. Some entities will apply neutral impedance grounding at the transformer to reduce the fault current for ground faults. In systems with single phase transformers, load unbalance is often high, requiring ground relays be set above the maximum imbalance to avoid nuisance tripping. This results in less ground relay sensitivity for ground faults involving impedance (other than solidly grounded faults). This system can also result in a higher risk of back feed conditions (fault current flowing through unfaulted phases of a 3-phase transformer) as discussed later in Section 9.1 (single phase devices).

6.2 3-Wire Uni-Grounded Wye

Uni-grounded wye or 3-wire systems are less common at medium voltage circuits in North America but more common internationally. These are also applied on transmission systems and support phase-to-phase connected loads without an insulated neutral conductor being brought to the load. These systems can accommodate different grounding methods to reduce ground fault current levels by applying neutral grounding resistors, reactors, or compensated neutral (CN) schemes. In these systems, unbalanced loads do not flow in ground relays allowing sensitive ground time overcurrent settings. These systems can also result in a higher risk of back feed conditions (fault current flowing through unfaulted phases of a 3-phase or phase-to-phase transformer) as discussed in Section 9.1, Single Phase Devices.

6.3 Ungrounded Delta or Wye

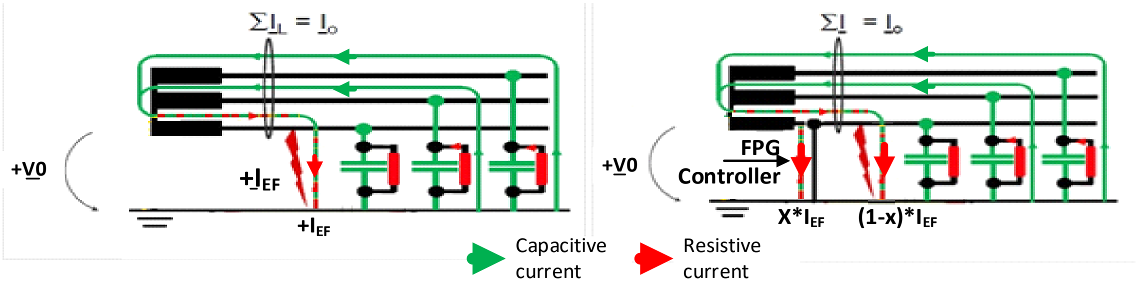
Delta or wye ungrounded systems support phase-to-phase connected load. These systems have a very high impedance to ground by design, as only the capacitance to ground from the conductors acts as the ground path during a ground fault. This can allow a ground fault to remain undetected on the system requiring manual isolation methods (non-automatic) to isolate faults.

Conventional overcurrent ground protection will not be effective on these systems. The practice of keeping the network energized in the presence of a single ground is not often used in overhead network applications that have public exposure. This system can also result in a higher risk of back feed conditions (fault current flowing through unfaulted phases of a multi-phase transformer) as discussed in Section 9.1, Single Phase Devices.

Sensitive ground fault protection can be achieved by tripping the entire system when a high zero sequence voltage is detected. In very small distribution systems with only a few amperes of charging current sensitivity and energy release can be competitive with rapid earth fault current limiters (REFCL) technologies.

6.3.1 Isolated Neutral with Faulted Phase Grounding

Isolated neutral (IN) with faulted phase grounding (FPG) can result in small ground fault currents produced by the phase-to-ground capacitive charging current (refer to Figure 6.3.1). FPG diverts the vast majority of ground fault current back into the controlled environment of the substation.



Fault **Fault with FPG**

Figure 6.3.1 Isolated Neutral System with Faulted Phase Grounding.

When a ground fault is detected on a circuit, the FPG controller initiates a single-pole close command to a switch in the substation that connects the faulted phase to the substation ground grid as illustrated in Figure 6.3.1

Depending on the ratio of the ground fault contact resistance to that of the substation ground grid resistance, resulting ground fault current at the fault site is reduced by 90 percent or more. Resulting ground fault currents under 0.5 A can be achieved depending on the network size.

This type of system is a potential solution for small networks in areas at medium or low risk of wildfires.

6.4 Grounded Delta

Delta grounded systems typically support phase-to-phase connected load. The corner of the delta can be solidly grounded, or non-effective grounded. This method is not common in medium voltage systems. Zero-sequence voltage (3V0) sensing methods can be used to alarm or trip for ground faults, but tripping selectivity and coordination are problematic.

6.5 Non-Effective Grounding for Wye Grounded Systems

A high-impedance or non-effective ground may be permanently installed or switched daily or seasonally by shunting the high-impedance to create a solid ground at times of low fire risk. Non-effective grounding will reduce the energy at the arc but may not eliminate it. With any of the non-effective grounds or ungrounding, a ground fault on the system will result in a temporary overvoltage (TOV) condition where the two unfaulted phases can rise to phase-to-phase potential, so insulation and surge arrestors must be appropriately rated for such voltages. Potentially, this condition can be left on the system for extended periods based on the risk as determined by the operators and based on the insulation of the system.

Transformer neutral bushings should be properly insulated/rated for the expected service.

There are variations of high-impedance or non-effective grounding:

- High Resistance Ground
- High Reactance Ground
- Compensated (Resonant) Ground
- Hybrid Grounding

These variations are shown for a wye transformer secondary winding in Figure 6.5. This figure is for illustrative purposes. Most applications will either permanently install a single grounding method or a single grounding method with a bypass switch. Compensated (resonant) ground and related protection methods are described in detail in Section 7.

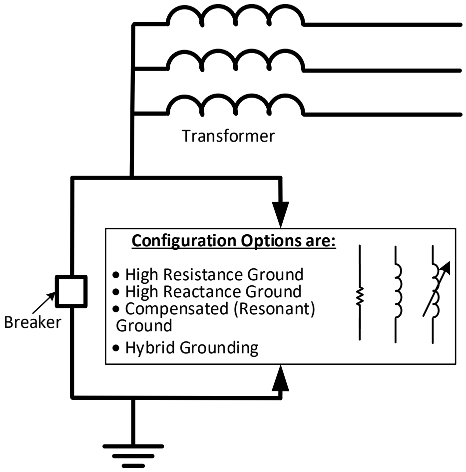


Figure 6.5 Hybrid (Switched) Grounding.

6.6 Feeder Ground Fault Protection for Non-Effective Grounded Systems

For this condition, in addition to temporary overvoltage (TOV) concerns, overcurrent relay sensitivity and selectivity can be problematic, if the protection system is not adjusted or changed to accommodate the higher impedance and lower ground fault current levels.

One method applied to improve ground relay sensitivity is a small-ratio core balance toroidal CT around the phase conductors. For directional determination, zero-sequence voltage can be used to polarize the relay (refer to Figure 6.6).

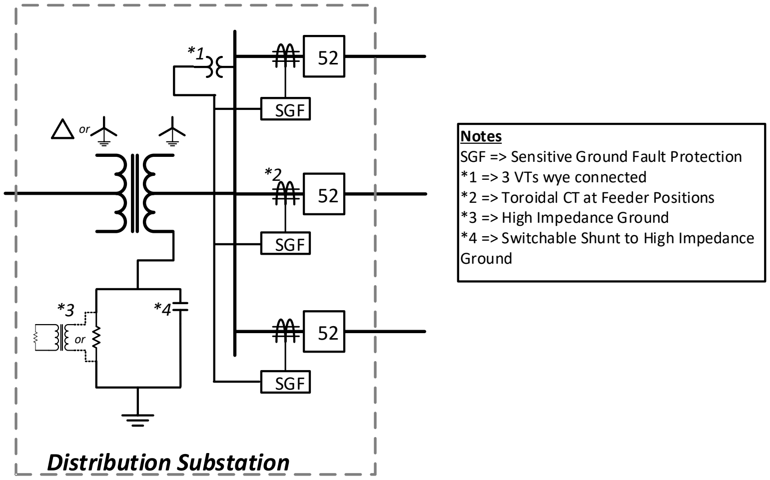


Figure 6.6 CT and VT application for ground fault protection for non-effective grounded systems.

Some protection considerations for systems using non-effective grounding methods are described below.

Ungrounded:

- The residual current in the faulted feeder will lead 3V0 by approximately 90˚.
- Protection methods that can be employed:
    - Zero-sequence voltage (only used for polarizing, or for bus bar and transformer protection)
    - Varmetric (V0*I0* SinΦ element) or I0*SinΦ element
    - Fault Inception Transient (FIT) ground fault detection element
    - Susceptance element

High Resistance Grounding:

- The residual current in the faulted feeder will be mostly in phase with 3V0
- Protection methods that can be employed:
    - Zero-sequence voltage (only used for polarizing, or for bus bar and transformer protection)
    - Wattmetric (V0*I0*CosΦ) element or I0*CosΦ element
    - Fault Inception Transient (FIT) ground fault detection element
    - Conductance element

High Reactance Grounding

- The residual current in the faulted feeder will lead 3V0 by less than 90˚
- Protection methods that can be employed:
    - Zero-sequence voltage (only used for polarizing, or for bus bar and transformer protection)
    - Wattmetric (V0*I0*CosΦ) element or I0*CosΦ element
    - Fault Inception Transient (FIT) ground fault detection element
    - Conductance element

6.7 Selectivity and Coordination in Non-Effective Grounded Systems

Some challenges can occur when converting low impedance grounded to non-effective grounded systems.[24] Depending on the level of ground current available, time current coordination might not be achievable using ground overcurrent protection methods. Coordination with larger fuses may not be possible. Ground-fault detection may not be possible with line reclosers' overcurrent relay elements. If the feeder relays are equipped with the proper sensitive ground fault protection, downline reclosers can be incorporated into a clearing scheme without the sensitive ground fault protection implemented in the reclosers.

Selectivity can be achieved by applying a direct transfer trip scheme to each line recloser and varying the tripping time delay to achieve sequential tripping until the fault condition on the feeder relays is eliminated.

6.8 Detecting Transformer and Bus Faults for Non-Effective Grounding

Some challenges can occur when converting solidly grounded to non-effective grounded systems.[25] If a ground fault occurs on the bus with a non-effective ground source, the resulting small ground current may not operate phase-based bus differential protection. Residual overvoltage or zero sequence voltage could be used. Similarly, a ground fault in the source transformer may not operate phase differential protection. An interlock scheme can be created using the feeders' sensitive ground fault elements, a bus main sensitive ground fault element, a 59N element, and logic to correctly determine the fault location. A simple description of the interlock scheme is described below:

- The 59N element of the bus protection is delayed allowing the feeder protection to operate
- If a high-impedance ground fault is declared by any feeder relay's sensitive ground fault element, then the ground fault is on a feeder and not in the bus or transformer zone of protection.
- If a high-impedance ground fault is declared by the bus main relay's sensitive ground fault element, and not declared on any feeders, then the ground fault is on the bus
- If a high-impedance ground fault is declared by the bus main relay's 59N element, and not declared by the bus main relay's sensitive ground fault element, then the ground fault is in the transformer zone of protection.

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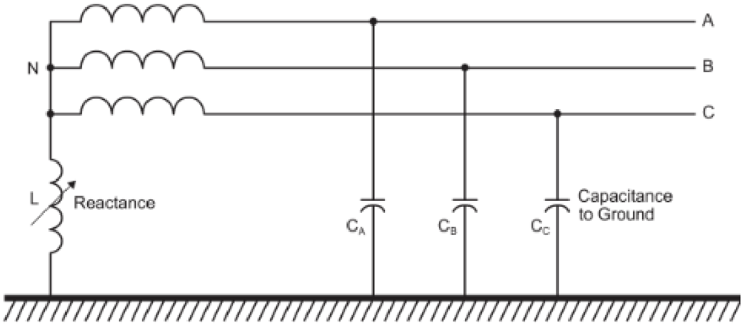
[24] H. Bayat, T. Bains, A. Zamani, M. Webster, J. Rorabaugh, and A. Tores, "Rapid ground fault detection in compensated-grounded systems: design and testing", Western Protection Relay Conference, 2020.

[25] H. Bayat, Y. Yin, D. Ransom, A. Zamani, M. Webster, J. Rorabaugh, and A. Tores, "A Proposed Scheme to Protect Transformer Bank and Arc Suppression Coil in Compensated-Grounded Distribution Systems", Western Protection Relay Conference, 2021.

7. COMPENSATED NEUTRAL SCHEMES

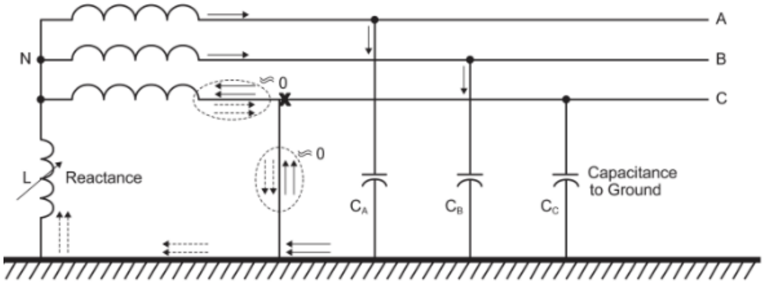
The Petersen Coil (a tuned reactor) was first developed in Germany by Waldemar Petersen in the early 1900's and appears in AIEE papers beginning in 1922. This grounding method was possibly the first compensated neutral (CN) method and included a tuned reactor in the substation neutral to ground connection that is sized to match the capacitance to ground of the circuits connected to the transformer and the system including any contingencies (as shown in Figure 7A). This capacitance to ground is not related to the load or power factor but is due to the natural capacitance to ground of the connected overhead conductors and underground cables. This method of grounding can reduce ground fault currents to such low levels that temporary ground faults may self-extinguish without any relay or interrupter operation (as shown in Figure 7B). These were typically installed to increase service continuity and to reduce damage to electrical components from ground fault currents in underground systems or in areas with heavy lightning. CN grounding is very common in Europe and Asia but is not used at all in some regions around the world. As wildfire risk has increased, applying modern versions of the CN has seen renewed usage because of the very low ground fault currents that can be achieved. This method does not decrease multiphase fault currents. This grounding method is difficult to apply to multi-grounded distribution systems with phase-to-neutral load connection.

The coil is typically tuned close to the resonant point at the fundamental frequency with the phase-to-ground charging capacitance of all feeders connected to the same galvanically connected system. The coil compensates for the residual capacitive current leaving only a small mismatch reactive current plus the remaining resistive current (from system conductance, arc suppression coil (ASC) iron losses and any deliberate added damping) plus harmonics. On modern systems, when the system capacitance changes (e.g. due to switching on the network), the arc suppression controller can automatically tune close to the new resonant point. As with isolated neutral (IN) systems, healthy phase voltages can reach line to line voltage levels when a ground fault occurs, and this can have implications for insulation levels.



Healthy System with Petersen Coil

Figure 7A Simplified diagram of a CN system.[22]



Ground-Fault on System with Petersen Coil

Note: Line conductance and coil losses are not shown here.

Figure 7B Simplified diagram of a CN system.[22]

When a ground fault occurs, the system neutral treatment takes on critical importance. It dictates how much energy will be released into a ground fault and hence the probability of ignition. International statistics indicate that typically more than 80 percent of faults on medium voltage distributions systems are ground faults, of which typically more than 80 percent are transient in nature. High-impedance neutral grounding decreases the arc energy released compared to alternative methods which significantly reduces the risk of ignition.

To provide for a consistent understanding of the quantities and descriptors commonly used throughout this section and beyond, the following Table 7 provides references.

Table 7 Formula for quantities and descriptors commonly used in this document.

CURRENT	Residual current	$\underline{I}_{Residual} = \underline{IA} + \underline{IB} + \underline{IC}$
	Zero-sequence current	$\underline{I0} = (\underline{IA} + \underline{IB} + \underline{IC}) /3$
VOLTAGE	Residual voltage	$\underline{V}_{Residual} = \underline{VA} + \underline{VB} + \underline{VC} = 3*\underline{V0}$
	Zero-sequence voltage	$\underline{V0} = (\underline{VA} + \underline{VB} + \underline{VC})/3$
	Neutral Voltage displacement	$NVD = (\underline{VA} + \underline{VB} + \underline{VC}) /3 = V0$

Note: Underlined quantities in the table are phasor quantities.

The residual fault current can be very small in these systems (in the order of 5-15 amps for galvanic faults, and below 1 amp for high impedance faults). For sensitive protection, it is preferred to use a low ratio, core-balance CT (also known as a cable ring CT or flux-summing CT) for improved measurement accuracy. In some regions, phase CTs are connected in a wye configuration (also known as Holmgren Connection) that provides the 3I0 current that can be used for ground fault detection. Residually connected CTs have greater measurement errors that challenge protection sensitivity. Using an incremental residual current calculation that removes the pre-fault measurement error can help improve sensitivity. Because of the low fault current and due to the properties of the compensated neutral system (e.g. slow recovery speed of the faulted phase voltage after the arc extinguishment), single-phase faults in these systems can be intermittent in nature. This can challenge protection systems that use an incremental quantity. Using the zero-sequence voltage as the fault detector and using the positive-sequence voltage phase as a reference can help address these challenges and improve the sensitivity of directional residual overcurrent methods.

The advantages of CN systems are the following:

- Very small ground fault current (assuming mismatch and damping is small)
- Touch and step voltages are very small.
- Outages due to ground faults can be minimized, particularly for transient ground faults
- Detecting ground faults is relatively straight forward and dependable compared to the other schemes. Sensitivity to high-impedance ground faults of 10,000 ohms at 10kV and 20,000 ohms at 20kV is achievable.

The disadvantages of CN systems are the following:

- May need higher line equipment voltage ratings (unless already insulated for line-to-line voltages), since during a single-phase-to-ground fault, the phase-to-ground voltages of each unfaulted phase increase by a factor approaching $\sqrt{3}$
- A few amps of current remain at the ground fault site (resistive part of the fault current and harmonics are not compensated by the ASC)
- Surge arrester maximum continuous operating voltage (MCOV) level requirements are higher
- Fault selectivity and fault locating may be challenging

Some additional methods are now being applied in conjunction with neutral reactors to reduce ground fault currents and fire ignition risk event further. Some of these methods apply power electronics to drive ground fault currents to as low as 0.2 A primary.

7.1 Use of Terms for Compensated Neutral Systems

The use of compensated neutral (CN) schemes and the addition of new technologies has led to the use of imprecise and overlapping terms and acronyms to describe the various schemes and systems. In this report, terms that are trademarked or copyrighted are avoided. In addition, one acronym might have 2 slightly different meanings in various publications. For this report the following definitions are used:

A. Arc Suppression Coils (ASC) – Arc suppression coil (ASC), Petersen Coil, and historically ground fault neutralizers (GFN) are alternative names for an adjustable reactor in the transformer neutral for the purpose of limiting ground fault current. This creates a compensated neutral (CN) system or resonant grounded neutral (RGN) system.

B. Residual Current Compensation (RCC) – Residual current compensation (RCC) is an adjustable inverter connected in parallel with an arc suppression coil (ASC).

The RCC injects current into the neutral to cancel out residual fault current on a compensated neutral (CN) system during ground faults.

C. Rapid Earth Fault Current Limiter (REFCL) – Rapid earth fault current limiter (REFCL) is a generic term for systems designed to limit the magnitude of single-phase ground fault currents to very low levels. This is typically an arc suppression coil (ASC) combined with a residual current compensation (RCC).

D. Please refer to the use of these terms in Section 7.2.

7.2 Residual Current Compensation

Residual current compensation (RCC), also referred to as rapid earth fault current limiters (REFCL), are an enhancement to the CN system that adds power electronics to inject current into the substation ground grid to reduce ground fault currents to very low levels.[26]

CN systems reduce the reactive component of ground fault current to low levels by matching the system capacitance to ground with neutral connected inductance. The level of ground fault currents is then driven much lower by power electronics that inject the inverse of the remaining residual ground fault current including the resistive component and any mismatch of the reactive component.

A well-tuned RCC can reduce voltage on the faulted phase to less than 250 volts during high impedance ground faults.[27] Energy release is kept lower than in CN systems by reducing the fault current of high impedance ground faults and by further extinguishing arcing such as that found on downed wires or restriking cables. For transient faults the RCC can extinguish the arc with no interruption to customers. While similar reductions can be achieved in the initial fault with techniques such as faulted phase grounding (FPG), the fault confirmation process is typically a lower energy release with an inverter. This lower energy release during fault confirmations results in a reduced probability of ignition both on the initial fault and when confirming if a fault was transient.

These systems also have benefits in detecting high-impedance ground faults and have been used to detect ground faults with resistance in excess of 20 kΩ at 20kV and current as low as 0.5 A. To achieve this sensitivity, capacitance to ground imbalance and other sources of ground current noise must be reduced. Capacitance balancing between the three phase conductors can be challenging when the systems are not entirely three-phase. Typically, this is done by deploying capacitive balancing units to complement the missing phase-to-ground capacitances.

This application requires that all distribution loads be connected phase-to-phase with no load connected phase-to-ground or phase-to-neutral. During a single phase-to-ground fault the two unfaulted phases experience elevated phase-to-ground voltages due to the neutral voltage shift which may stress the insulation of line equipment, underground cables, and surge arrestors. One challenge for the systems currently available is that these can

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[26] The RCC Ground Fault Neutralizer — A novel scheme for fast earth-fault protection; CIRED 2005 - 18th International Conference and Exhibition on Electricity Distribution; https://ieeexplore.ieee.org/document/5427849

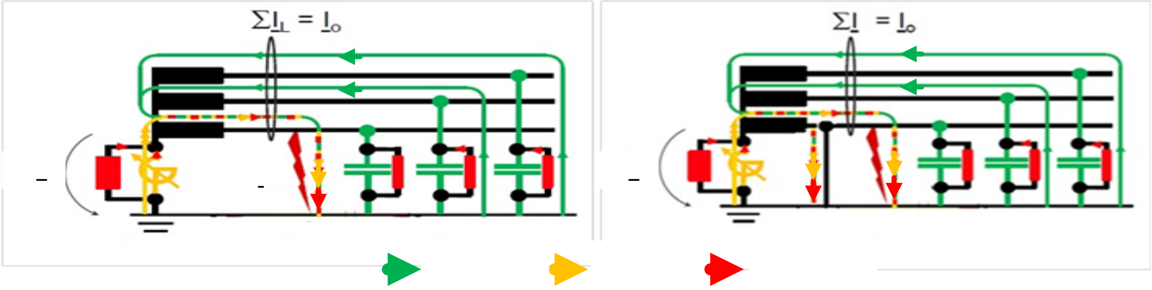
[27] REFCL Functional Performance Review, Report for Energy Safe Victoria; ESV_REFCL Functional Performance_v0 (First Issue); Prepared by: Roger Riley (Managing Director - APAC) Jon Bernardo (Principal Engineer) Date: 14/10/2020

determine which feeder is faulted but solutions to provide selective tripping for line reclosers are less available. High-impedance fault location at the line recloser level is an area of continued technology development.

7.3 Faulted Phase Grounding

CN with faulted phase grounding (FPG) reduces the total ground fault current to typically less than 1 amp. When a ground fault is detected on a circuit, the controller initiates a single-pole close command to an interrupter in the substation that connects the faulted phase to the substation ground grid as illustrated in Figure 7.3.

This diverts the vast majority of the small ground fault current back into the controlled environment of the high voltage and medium voltage substation. Depending on the ratio of the ground fault contact resistance to that of the substation grounding system resistance, the resulting ground fault current at the fault site can be reduced by 90 % or more. Ground fault currents less than 0.5 A primary can be achieved depending on the size of the distribution system.



Fault with CN **Fault with CN and FPG**

Figure 7.3 Compensated Neutral System with Faulted Phase Grounding.[28]

7.4 Application of Specialized Protection Methods

Detecting ground faults with non-directional time overcurrent elements is not effective with CN systems because of the extremely low fault current levels. The sub-sections below briefly describe some of the protection methods used to detect ground faults in CN systems.

For solidly or low impedance grounded systems, plain residual overcurrent protection is generally used, supplemented by a sensitive ground fault (SGF) stage for detection of higher resistance faults. Even with SGF protection, sensitivity is still relatively poor (only tens to hundreds of ohms). For non-effective grounded systems, a number of selective, robust, and reliable ground fault detection algorithms are available providing validated practical sensitivity of 5 – 10 kΩ.

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[28] H. Borland and M. McCormack, "Safety, Reliability and Efficiency – beyond the grid edge," 2023 IEEE PES Grid Edge Technologies Conference & Exposition (Grid Edge), San Diego, CA, USA, 2023, pp. 1-5, doi: 10.1109/GridEdge54130.2023.10102704.

7.4.1 Directional Residual Overcurrent Methods

This technique measures the reactive or active component of residual current and establishes direction by determining the angle between this quantity and the neutral voltage displacement V0. It uses a suitable relay characteristic angle (RCA) between the current quantity and the residual voltage.[29]

On isolated neutral (IN) systems, this technique measures the reactive component of residual current (refer to Figure 7.4.1A).

- Varmetric (V0*I0*SinΦ element) or I0*SinΦ
- RCA = -90°

On CN systems, this technique measures the active component of residual current (refer to Figure 7.4.1B).

- Wattmetric (V0*I0*CosΦ) element or I0*CosΦ element
- RCA = 0°

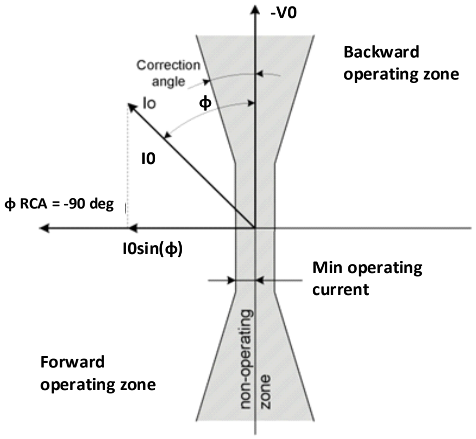

Figure 7.4.1A Characteristic of I0*SinØ method, IN System

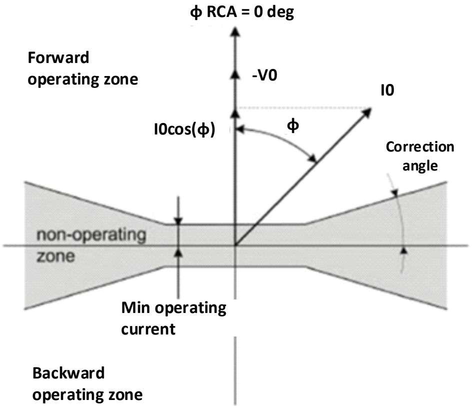

Figure 7.4.1B Characteristic of I0*CosØ method, CN System

7.4.2 Fault Inception Transient Methods

Fault inception transient (FIT) detection relays (a.k.a. Wischer method[29]) use the charge redistribution (discharge transient due to discharge of the faulted phase-to-ground capacitances and the charge transients of the two healthy phase and ground capacitances) at the time of fault inception to make a directional decision. Algorithms are typically not phasor based but are based on evaluation of voltage and current samples at high (~10 kHz) sampling frequency. In non-effective grounded systems, the initial transient ground fault currents and voltages are generally quite large for 2 – 3 milliseconds. Figure 7.4.2A shows a typical transient characteristic. If the magnitude of the zero-sequence voltage reaches the set threshold, a small time period is opened to compare the slopes (polarities) of the zero-sequence voltage and the residual current samples. The faulted Feeder (A) can be distinguished in Figure 7.4.2B by the same slopes (polarities) that exist between the current I0 and the voltage -V0 samples.

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[29] NEW SOLUTION FOR DETECTING SINGLE PHASE-TO-GROUND FAULTS IN RESONANT-GROUNDED SYSTEMS; CIRED 2019; Gergely PÓCSI, Ferenc RADVÁNSZKI, György CSIPKE Hungary'.

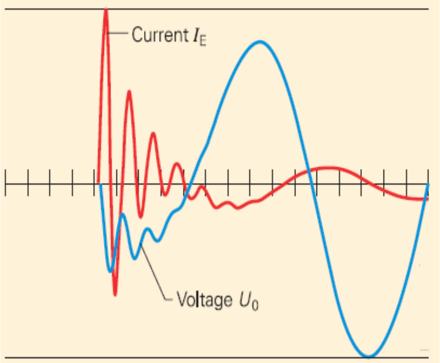
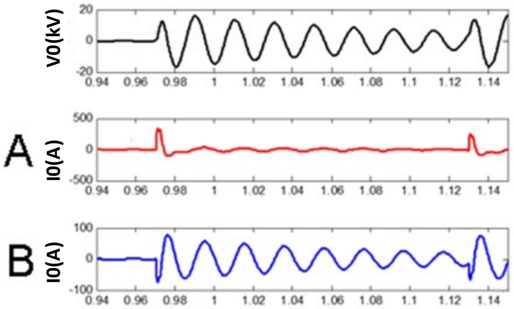


Figure 7.4.2A Transient characteristic of I0 and -V0.



7.4.2B Faulted Feeder A and healthy Feeder B.

The sensitivity of the basic FIT method is limited to low ohmic ground faults as a fault resistance of a few hundred ohms will attenuate fault ignition transients significantly.

7.4.3 Charge Voltage (qu) Methods

The integral of I0 is equal to the charge q0(t) of the protected feeder. This relationship is shown in Figure 7.4.3A for a low ohmic fault, where the charge q0 (integral of i0(t)) is plotted versus the zero-sequence voltage V0. The gradient (a proportionality factor between q0 and V0) is the zero-sequence-capacitance C0 of the feeder. For the healthy feeder there is a linear relationship between q0 and V0 and it describes a straight line with a positive slope. For the faulted feeder, a linear relation between q0 and V0 is no longer evident. The trajectory of the faulted feeder starts with a negative slope in comparison to the healthy feeders. This qu method can also detect high ohmic ground faults up to several kilo-ohms if the integration period for the residual current is enlarged. Figure 7.4.3B shows the corresponding charge voltage (qu) method diagram of a high ohmic ground fault.

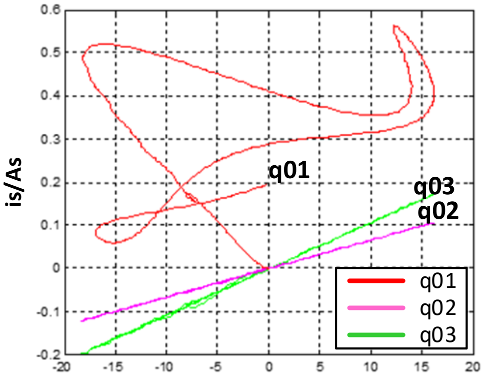


Figure 7.4.3A - qu diagram for a low ohmic fault.[30]

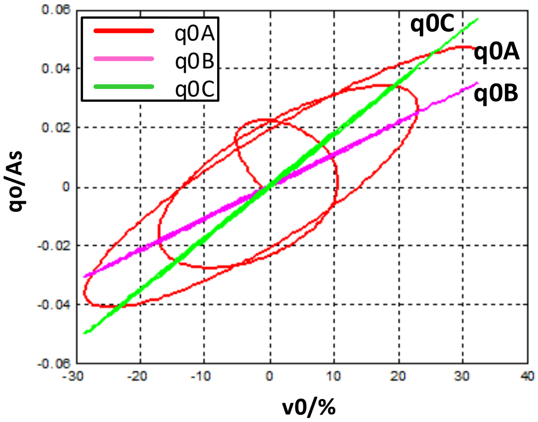


Figure 7.4.3B - qu diagram for a high ohmic fault.[30]

7.4.4 Transient Reactive Power Methods

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[30] G. Druml, R. -W. Klein and O. Seifert, "New adaptive algorithm for detecting low- and high ohmic faults in meshed networks," CIRED 2009 - 20th International Conference and Exhibition on Electricity Distribution - Part 1, Prague, Czech Republic, 2009, pp. 1-5.

Transient Reactive Power (TRP) methods use a derivative function of voltage V0 and can be physically interpreted as the instantaneous reactive power. Waveforms in Figure 7.4.4 shows that the zero-sequence voltage and current signals of the faulty feeder have opposite polarity only in a very short time after fault inception, while the derivative of zero-sequence voltage has opposite polarity during entire transient period.

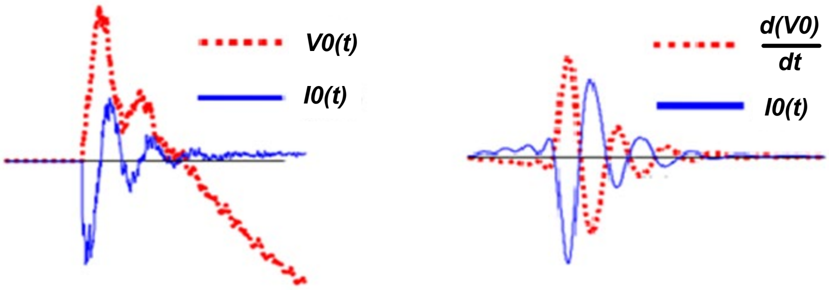

Figure 7.4.4 Comparison of V0 and I0 with d(V0)/dt and I0.[31]

7.4.5 Admittance Methods

Zero-sequence admittance (Y0) methods have been used since their development over thirty years ago in Poland and they have proven very robust and reliable.[32] Neutral or zero-sequence admittance protection is based on evaluating the phasor quotient Y0 = I0/V0. It eliminates the influence of fault resistance because the fault resistance does not change the ratio of I0 and V0; both quantities are reduced in similar proportion as a function of fault resistance. Figure 7.4.5A shows a typical neutral admittance characteristic. With admittance-based protection, changing the method of system neutral ground connection is straightforward. Admittance protection can be universally applied in systems with isolated, arc suppressed, and resistance grounded networks as demonstrated in Figure 7.4.5B. This is of particular value during a transitional phase from one neutral treatment to another in terms of cost containment and operational simplicity during actual changeovers.

Some RCC devices integrate the inverter controller with a zero-sequence admittance algorithm during fault confirmation. As the current compensation is changed, they look for which feeders show a positive change in admittance and which feeders show a negative change in admittance to determine the faulted feeder.

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[31] Xue Yongduan, Xu Bingyin, Chen Yu, Feng Zuren and P. Gale, "Earth fault protection using transient signals in non-solid earthed network," Proceedings. International Conference on Power System Technology, Kunming, China, 2002, pp. 1763-1767 vol.3

[32] J. Lorenc, K. Marszalkiewicz and J. Andruszkiewicz, "Admittance criteria for earth fault detection in substation automation systems in Polish distribution power networks," 14th International Conference and Exhibition on Electricity Distribution. Part 1. Contributions (IEE Conf. Publ. No. 438), Birmingham, UK, 1997, pp. 19/1-19/5 vol.4, doi: 10.1049/cp:19970569.

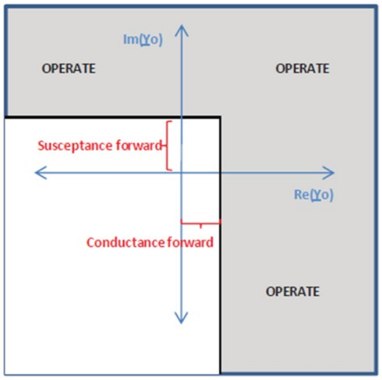

Figure 7.4.5A Typical operate characteristic of Y0 function.[33]

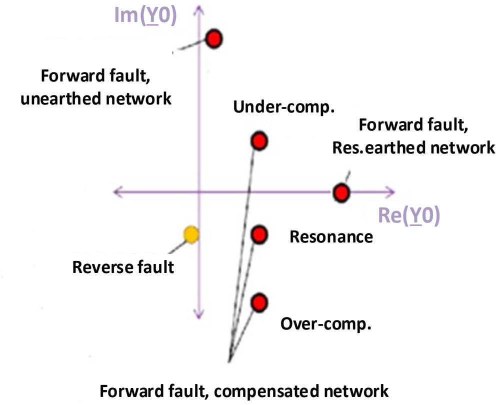

Figure 7.4.5B Y0 locus for different neutral treatments.[33]

7.4.6 Multi-frequency Admittance Methods

Multi-frequency admittance (MFA) protection includes harmonic quantities in its calculations, to improve sensitivity and identification of faulty/healthy feeders and improve performance for intermittent faults. The harmonic components of the admittance phasors behave similarly to the isolated neutral (IN) system, i.e. on the faulty and healthy feeders they point in opposite directions, due to the fact that ASC is not effective at harmonic frequencies. This applies regardless of the degree of detuning of the ASC. The MFA function also has a self-adaptive nature, which enables operation without a damping resistor and can be applied to isolated neutral (IN) systems. Figure 7.4.6 shows a typical characteristic.

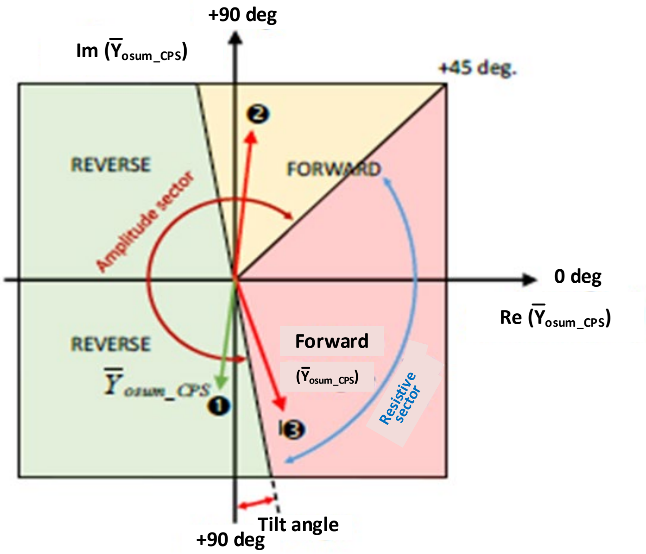

Figure 7.4.6 Directional characteristic of MFA.[33]

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[33] H. Borland, "Earth Fault Protection Enablers For Migration To High Impedance Neutral Earthing at Medium Voltage." IET International Conference on Developments in Power System Protection (DPSP). Newcastle upon Tyne, UK March 2022

7.4.7 Change in Admittance Methods

Directly measured residual quantities may be replaced with the changes in these parameters resulting from a ground fault. Such a difference (delta) mode (ΔY0) is particularly valuable with high levels of asymmetry. This mode takes into account pre-existing conditions:

$$\Delta Y0 = [I0\text{-fault} - I0\text{-prefault}] /\text{-} [V0\text{-fault} - V0\text{-prefault}] = \Delta I0/\text{-}\ \Delta V0$$

In delta mode, the residual voltage needs to be in excess of the set threshold. The change in the residual voltage must exceed minimum detectable change (typically around ~0.01*Vn, where Vn is the rated phase-to-ground voltage) and the residual current must exceed a set threshold.[34]

7.4.8 Change in Negative-Sequence Current Methods

The change in negative-sequence current method is based on the calculated values of the following:

- Three times the negative-sequence component
- The change is three times the negative-sequence component due to a ground fault

Figure 7.4.8 shows a typical operating characteristic.

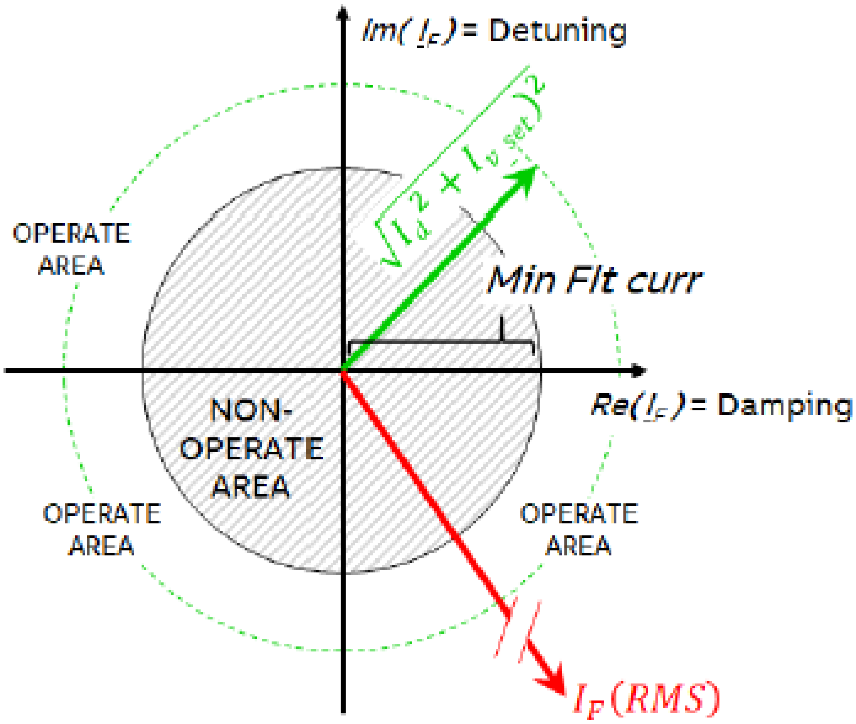

Figure 7.4.8 Change in Negative-Sequence Current Characteristic.[33]

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[34] J. Roberts, H. Hector and D. Hou, "Review of Ground Fault Protection Methods for Grounded, Ungrounded and Compensated Distribution Systems," Proceedings of the 28th Annual Western Protective Relay Conference, October 2001, Spokane, Washington

7.4.9 Harmonics

Operating on harmonics is a non-fundamental frequency technique. Harmonic currents are present on a healthy system with non-linear loads. On compensated systems, the ASC has no effect on the harmonic current (provided that no saturation occurs). During a ground fault, harmonic currents will be present in the healthy feeders as well as in the faulted one. The 5th harmonic is generally the highest amplitude harmonic during a ground fault. The actual 5th harmonic current values for the substation in question need to be measured prior to selecting application settings.

7.4.10 Concurrent Algorithms

All fault detection methods have limitations. The various methods handle certain fault types and characteristics better than others. Fundamental frequency-based methods are complemented by methods using transients and harmonic components. For all these reasons, some practitioners have recommended that multiple (complementary) forms of ground fault detection run concurrently in a single device.

7.5 Network Protection

Medium voltage circuits can be long and/or heavily loaded. Downstream devices like pole-mounted reclosers and pad-mounted interrupters with sensors for fault passage indication (FPI) provide fault tripping selectivity. Figure 7.6 below shows a simplified network diagram with three downstream devices out along the network.

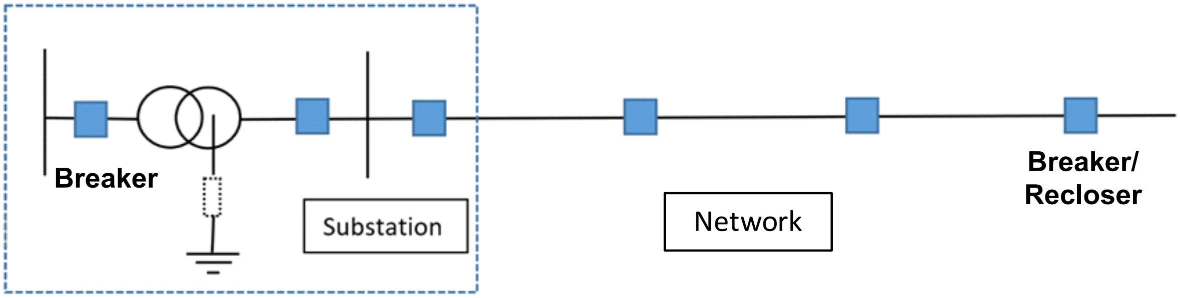

Figure 7.6 – Simplified network diagram.

Selective tripping along the network devices is important to minimize outages. Substation and downstream devices will typically be set to coordinate using time only (e.g. a coordination margin of 0.3 s or less). Downstream devices, sensors, and FPIs on non-effective grounded systems must provide directional ground fault detection. Availability of suitable detection algorithms such as wattmetric and fault inception transient (FIT) detection to downstream reclosers are of great value.

7.6 System Wide Ground Fault Protection

On non-effective grounded systems or CN systems, ground fault protection can be provided by an overvoltage relay measuring V0 or 3V0 on the medium voltage bus. This method will not provide for selective tripping for an individual feeder or pole mounted line recloser and is typically applied to provide general indication of a ground fault in the system or backup protection for the feeders. This illustrates the need for FPI devices to achieve selective tripping.

Some of the protection methods detailed in the subsections above can be used to provide FPI, whether configured to alarm only or selectively trip devices.

8. INCIPIENT FAULT DETECTION

This section discusses the various technologies, trials and solutions being developed or applied for incipient or “emergent” fault detection that are potential precursors to fire ignition risks as described in Section 3: Fault Behavior and Ignition Risks of this report.

The gold standard sought by the industry includes methods to detect incipient faults with enough time to take action before high current faults or ignition occurs. Several new sensor-based methods are showing promise at detecting some incipient fault conditions but there will always be some faults that occur suddenly, such as those caused by lightning, falling trees, or car pole accidents.

Principles used for Incipient Fault Detection

Broadly, the principles used for the technologies and solutions for incipient fault detection can be classified under the following categories.

- Pattern recognition
- Corona discharge detection / partial discharge analysis
- Remote sensing and LiDAR
- Falling Conductor Detection (FCD)
- Traveling Wave (TW)
- Fiber-based line monitoring

These categories cover incipient fault detection for both transmission and distribution lines. It has been found that the trials and experiences of some of these categories are more widely known and used for transmission lines, compared with those that are used on distribution lines.

The pattern recognition, corona discharge detection, falling conductor detection, TW, and fiber-based line monitoring categories are more relevant to the expertise of the IEEE PSRC scope from the viewpoint of potential pre-ignition causes. Remote sensing and LiDAR are primarily adjacency issues associated with possible line-fault situations arising from momentary or incipient vegetation related adjacency situations.

Distribution lines and networks experience more transient faults and abnormalities like high-impedance faults than do transmission networks. The protective relaying technologies and schemes using intelligent electronic devices are also widespread and mature in transmission line protection and provide more access to real-time fault data and analysis capabilities.

However, the distribution system is much more extensive and has many more touch points than the transmission system. Protection devices on the distribution system have been evolving from overcurrent relays at the substation and fuses throughout the distribution network to much more advanced systems that include reclosers, line sensors and distributed communications.

8.1 Pattern Recognition Methods

Pattern recognition methods analyze the data coming from devices (relays, sensors, and other devices) installed throughout the distribution system. The data can be used with advanced analytics to detect and categorize these electrical anomalies and report possible fault precursors. These can include fault induced conductor slap, capacitor bank problems, and pre-failure clamp and switch problems.[35] This is making it possible to identify some potential incipient fault detection situations for distribution lines prior to a fault or ignition.

8.2 Corona Discharge Detection Methods

Corona discharge methods are well-understood and practiced for insulation integrity issues for power system equipment. For distribution and transmission lines two different methods have been successfully used to detect incipient fault conditions.

Drone or motor vehicle mounted UV cameras (UV-Ultraviolet spectrum) are used for overhead transmission and distribution line inspections. Corona discharge indicates bonding and connection integrity problems and could be used to identify possible fault precursor risks. Commercial availability of UV cameras (UV-Ultraviolet spectrum) for corona discharge is well-established. The challenge is to leverage this technology for cost effective and widespread deployment and/or service for transmission and distribution lines. Some literature is focused on the deployment of incipient fault techniques and effectiveness.[36]

Another method is based on sensors installed at 3-to-5-mile intervals along transmission or distribution lines. Combined with data analytics, this method can locate vegetation encroachment, insulation problems and broken conductor strands before a high current fault occurs.[37]

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[35] J. A. Wischkaemper, C. L. Benner, B. D. Russell and K. M. Manivannan, "Waveform analytics-based improvements in situational awareness, feeder visibility, and operational efficiency," 2014 IEEE PES T&D Conference and Exposition, 2014, pp. 1-5, doi: 10.1109/TDC.2014.6863349

[36] N. Davari, G. Akbarizadeh and E. Mashhour, "Intelligent Diagnosis of Incipient Fault in Power Distribution Lines Based on Corona Detection in UV-Visible Videos," in IEEE Transactions on Power Delivery, vol. 36, no. 6, pp. 3640-3648, Dec. 2021, doi: 10.1109/TPWRD.2020.3046161.

[37] K. L. Wong, T. Marxsen, M. Liang and J. S. Chahal, "A Novel Autonomous Technique for Early Fault Detection on Overhead Power Lines," 2019 IEEE 4th International Conference on Condition Assessment Techniques in Electrical Systems (CATCON), Chennai, India, 2019, pp. 1-5, doi: 10.1109/CATCON47128.2019.CN0027.

8.3 Remote Sensing and LiDAR Based Methods

There are various remote sensing options to monitor power-line corridors that focus more on equipment rather than on vegetation management close to electricity infrastructure.[38] With increased focus on surveying infrastructure through unmanned aerial vehicles (UAV) and the increased availability of LiDAR for infrastructure and environmental scanning, applications have started to leverage these technologies.[39]

Opportunities to integrate these technologies with other existing mechanical line monitoring methods (not within the scope of this report) help triage incidents and make better estimates of potential fire-ignition triggers for transmission and distribution lines.

8.4 Falling Conductor Detection Methods

Energized transmission or distribution circuit conductors can break and fall due to aging, annealing from a history of faults, storm stress, or splice or mounting hardware failure. One, two, or three energized conductor ends fall and contact the ground, producing an arcing fault that can trigger a wildfire. Arcing fault current may be low or undetectable so that fault protective relays do not operate or are slow to operate; the arcing and hazard are sustained as other sections in this report explain. This is especially valid when a conductor breaks and the downed conductor is left energized from the load side of the break point.

Falling Conductor Detection systems have been developed, starting around 2014, which are able to detect the electrical signature of circuit voltage and/or current changes that uniquely identify a conductor that has just broken and is in the process of falling towards the ground. With early break detection, there is adequate time to deenergize the circuit well before the conductors reach the ground – for example, a distribution conductor 10 meters (33 feet) in the air takes about 1.4 seconds to reach the ground after a break. Measurement systems can detect the break and trip adjacent switches to isolate the failed section in 150-500 ms, so that the conductor lands deenergized and no fault or arcing occurs.

One implementation for a distribution falling conductor detection, now being widely deployed by the developing utility.[40] This method gathers time-synchronized voltage measurements (synchrophasors) from substation feeder relays and circuit measurement devices like recloser or switch controls via a field-area communications network at 30 samples per second. These measurements are processed holistically with circuit algorithms to rapidly detect a conductor break and then trip adjacent switches. No circuit models or parameters are needed. The scheme is robust in the face of DER on the circuit and secure for common apparatus malfunctions that are not conductor breaks. In this scheme, measurements are required from both sides of a break to be detected.

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[38] Remote sensing methods for power line corridor surveys; Leena Matikainen; ISPRS Journal of Photogrammetry and Remote Sensing, Volume 119; September 2016, Pages 10-31 https://www.sciencedirect.com/science/article/pii/S0924271616300697

[39] Yangyu Chen, Jiayuan Lin, Xiaohan Liao, "Early detection of tree encroachment in high voltage powerline corridor using growth model and UAV-borne LiDAR, International Journal of Applied Earth Observation and Geoinformation, Volume 108, 2022, 102740, ISSN 1569-8432, https://doi.org/10.1016/j.jag.2022.102740.

[40] W. O'Brien, E.A. Udren, K. Garg, D. Haes, B. Sridharan, "Catching Falling Conductors in Midair – Detecting and Tripping Broken Distribution Circuit Conductors at Protection Speeds", Texas A&M Conference for Protective Relay Engineers, College Station, TX, March 2016.

Another method uses a sudden change in distribution system impedance (an impedance change ratio, ICR) to detect an open, falling conductor.[41] The proposed solution does not need dual-ended measurements and can detect a significant percentage of falling conductor conditions on a distribution feeder using a single PMU installed at the distribution substation.

Another scheme for detecting breaks in transmission circuits called transmission falling conductor detection uses disturbances of current synchrophasor measurements from one or both ends to detect breaks rapidly and selectively to trip/deenergize the line before the conductor reaches the ground and causes a fault.[42] Other implementations can detect breaks using current waveform data that is not time-synchronized and a sudden ICR.

Supplementary fault detection methods are required if a conductor falls and contacts the ground without breaking, such as can occur if an accident knocks a supporting structure to the ground.

8.5 Traveling Wave Monitoring

Incipient faults are defects that have not grown into a full-fledged line fault. Examples are: aged or polluted insulators arcing intermittently, a tree branch temporarily touching a line without causing a high-current fault, etc. Smoke, gases, and plasma from wildfires can significantly affect the air (the insulation medium) around the lines, subsequently, causing arcs and corona on the lines, towers, and insulators. These intermittent and low energy arcs can launch small traveling waves detectable by high-fidelity wideband sensors and relays.

A lot of these “events” can develop into a real fault in time, possibly starting a fire (e.g., line insulator breaking and arcing at or near dry vegetation on the ground). These events typically have lower magnitude traveling wave signals associated with them. However, these small magnitude TWs can be detected and can produce an accurate location (the TW system uses very high resolution and high-fidelity monitoring). This location can then be monitored, patrolled, or isolated/de-energized based on wildfire risk level.

The waves and disturbances on the line can be monitored and indeed some relays have a line monitoring feature. The locations can be tabulated to determine vegetation encroaching upon live conductors along a line. The entity can elect to issue an alarm or to trip circuit breakers when the event count exceeds the predetermined threshold. A line monitoring function can provide an effective way to detect recurrent high-impedance faults or incipient faults such as failing insulators and underground cable insulation issues.

The disadvantages of traveling waves in CN-systems are:

- Reflections on each change of the surge impedance, for example junction (overhead line to cable and opposite), bus bar, etc.
- Each secondary substation with additional branches generates noticeable discontinuity.

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[41] Y. Yin, A. Zamani, H. Kruger, H. Bayat, A. Marquez, A. Torres, I. Sanchez, K. Tran, and M. Webster, “High-Speed Falling Conductor Protection in Distribution Systems using Synchrophasor Data,” Western Protective Relay Conference, Oct. 2021.

[42] E. A. Udren, B. Koosha, C. Bolton, T. Rahman, “Transmission Line Falling Conductor Protection System Development at SDG&E®”, Texas A&M Conference for Protective Relay Engineers, College Station, TX, March 2022.

- Behavior of connected transformers as large capacitors (5 nF to 10 nF)
- Measurement with high frequencies in the MHz range.

8.6 Fiber-based Line Monitoring

Significant research is being conducted on fiber-based line monitoring. This technology has been successfully applied to underground petroleum pipes and undersea electrical cables. Overhead circuits with embedded or separately attached fiber optic cables can apply an optical transmitting device on one end of a fiber optic cable. A very small portion of the signal is constantly reflected back to the transmitter. Data analytics can be used to identify locations of partial discharge and other events such as vegetation encroachment, insulation breakdown, broken conductor strands, or high current faults.

9. IMPACT OF FUSES ON FIRE RISK

The IEEE C37.48 standard defines high voltage fuses as those applied on systems with voltage of 1,000 volts and higher.[43] Fuses are common protective devices installed in overhead distribution systems. These are relatively sensitive and inexpensive devices that can impact reliability, but fuses also have several characteristics that can impact fire risk.

In general, fuses operate and can isolate faults faster than circuit breakers and reclosers and therefore reduce the energy available for ignition. Section 4.3.2 discusses the application of fuse blowing or fuse saving schemes. When fuses operate, the element inside the fuse will burn and melt open and, in some situations, based on fuse design, could expel hot material that could ignite fuel and start a fire. For this reason, the entity must consider the risk in allowing the operation of the fuses. Some fuse designs expel fewer hot particles and may have been tested for spark emission to regional or national standards such as AS1033.1-1990.[11]

Current limiting fuses (CLF) are discussed in Section 9.4 and offer capabilities to reduce fault energy by both reducing the magnitude of fault current and duration of the event as compared to other types of fuses. Many CLF designs also prevent the hot particles produced during fault interruption when a fuse operates, removing the ignition risk at the fuse installation location.

9.1 Single Phase Devices

Single phase automatic operating protective devices in some cases can increase the risk of downed conductors remaining energized and causing fire ignition. If one phase of a multiphase overhead line breaks midspan, the conductor may contact the ground in two separate locations: one wire from the source side of the break and one from the load side of the break. The source side break on the ground may result in enough ground current to operate a protective device. If the source side protective device is a three-phase interrupter, all conductors at the fault location will be de-energized. If the source side protective device is a set of fuses only one fuse will pass fault current and operate. This would result in the other phase conductors remaining energized. If three-phase or phase-to-phase transformers

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[43] IEEE Std C37.48-2020: Guide and Tutorial for the Application of High-Voltage (> 1000V) Fuses and Accessories.

are connected on the load side of the blown fuse, it can result in low level currents flowing that have been known to ignite fires. This is sometimes called a back fed fault (refer to Figure 9.1). Due to the very low level of current flowing into the ground after the operation of a single fuse, this condition is impossible to detect with overcurrent relaying.

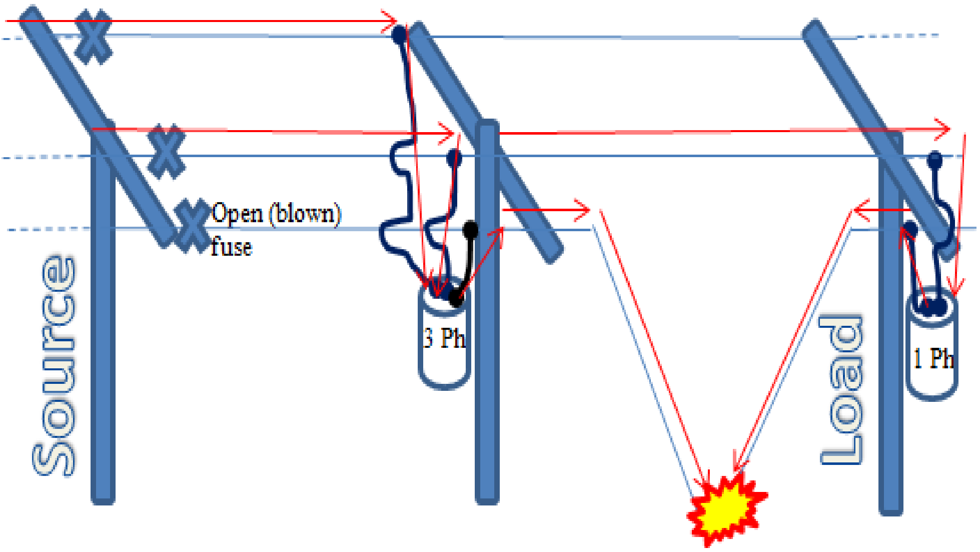

Figure 9.1 – Single fault with back feed through transformer.

9.2 Expulsion Fuses

Expulsion fuses are widely applied in distribution power systems, especially for overhead feeder lateral protections. Expulsion fuses consist of a fusible element made of tin, silver or copper. The fusible element is contained in an assembly called a fuse link. For overhead feeder applications, a fuse link is typically installed in a fuse holder of a fuse cutout assembly. The fuse link contains a special formula of chemicals that generates a large volume of gases when exposed to heat. When the fusible element melts due to the heat caused by overcurrent, the expanded gas pushes a fuse lead out of the fuse link. The released fuse lead in turn causes a spring-tensioned lever of the fuse cutout to operate and drops the fuse link out of its holder. Some expulsion fuse designs may use special arc quenching material and/or may incorporate exhaust control devices to reduce the amount of ejected material.

Operations of expulsion fuses interrupt the fault current in about one power cycle at a zero crossing of the current. Expulsion fuses do not limit fault currents. Before interrupting the fault current, expulsion fuses allow full available fault current to flow and therefore the released energy can be very high. Operations of expulsion fuses typically eject hot particles out of fuse links. If surrounded by flammable materials, like ground fuel accumulations such as dry grass and leaves, these ejected hot particles can cause wildfire ignitions. Some jurisdictions require annual clearing to bare earth around poles with expulsion type fuses.

9.3 Non-Expulsion Fuses

Many types of non-expulsion fuses are applied, often in high fire risk areas. These fuses typically do not eject molten material and may eliminate the requirement to clear vegetation around poles with fuses.

9.4 Current Limiting Fuses

Current limiting fuses (CLF) offer capabilities to reduce fault energy by both reducing the magnitude of fault current and duration of the event as compared to other types of fuses, circuit breakers, and reclosers.

Depending on their designs, CLF can be classified as full range, general purpose, and backup type of fuses. Full range CLF will successfully clear all currents in excess of its rated operating current. The other two types of CLF have blind spots and can miss lower-level faults that then result in ignition. Regardless, as its name implies, the major difference between current-limiting fuses from expulsion fuses is that these fuses limit fault current magnitude by interrupting the fault current before its first peak and well before its next zero-crossing.

A current-limiting fuse is typically constructed in a non-vented enclosure with many fusible elements in series and wound around a cylinder. The fuse body that encloses the fusible elements is filled with insulation material, typically quartz sand of high purity. When subjected to fault currents, fusible elements break up into multiple small series arcs. This arcing introduces a high resistance into the circuit and drives down the fault current before it reaches its peak. When the current is driven down to a low value, the arcs are extinguished. Unlike expulsion fuses, the arcing energy of current-limiting fuses forms fulgurite from quartz sand and causes a temperature rise to the fuse body.

These fuses can limit fault energy and do not emit molten particles. The cost of current-limiting fuses, especially for those full range or general-purpose fuses, is generally much higher than the expulsion fuses and they have limited ability to coordinate with load side protective devices.

9.5 Electronic Interrupters

Small single phase vacuum interrupters are available that can be installed in place of fuses. These devices can be programmed to trip or lockout on a single phase or three phase basis. These can be applied to reduce the risk of low-level fault current flowing through transformer primary windings or back fed faults.

10. CONCLUSIONS

Public Safety Power Shutoff (PSPS) is a method increasingly used by many utility companies to avoid the risk of wildfire ignition during periods of extreme fire risk. These planned shutoffs can reduce the risk of wildfire ignitions, but they also increase customer outage times.

No single method or technology eliminates the risk of wildfire ignition from electrical infrastructure but applying different layers of methods discussed in this report can reduce the risk. Careful consideration and application of different methods that are applicable to local conditions may eventually be able to reduce or prevent PSPS implementation.

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