Protective Relaying Methods For Reducing Arc Flash Energy

Johnny Simms
Member, IEEE
Basler Electric Company
4216 Maureen Drive
Charlotte, NC 28205-4158
johnnysimms@basler.com

Gerald Johnson
Senior Member, IEEE
Basler Electric Company
11502 Allecingie Parkway
Richmond, VA 23235-4302
geraldjohnson@basler.com

***Abstract* - This paper reviews progress in Arc Flash standards and requirements and the protective relaying techniques used to reduce Arc Flash energy, primarily through "high speed detection and operation". In some cases, the high speed zone is permanent and in others it is switched in during maintenance or repair. The need for high speed "backup" Arc Flash protection will be discussed. Using a single high speed zone of protection, thus establishing the level of "personal protective clothing", begs the question "what if the single high speed zone fails"? Several Arc Flash clearing time examples will demonstrate this concern.**

***Index Terms* – Arc Flash standards, high speed detection, zone of protection, flash protection boundary, Arc Flash clearing time**

I. Introduction

Within the realm of power system design and operation, there should be no greater concern than the safety of the men and women who operate and perform maintenance on the system. Not only must electrical system designers implement safeguards to protect equipment and processes, they also must evaluate the hazards to personnel presented by arcing faults, commonly referred to as Arc Flash or Arc Fault.

In many facilities, it is common practice to choose protective device settings based on "fault current" coordination with downstream protection which prevents unwanted tripping for non-fault conditions such as high load currents, motor starts, etc. This design and coordination methodology helps to avoid nuisance trips that may result in undesired interruption, costly shutdowns and restarts. However, this design and setting methodology may perform poorly when the focus is on protecting people who work on energized equipment.

This paper introduces the concept of a high speed backup zone and reviews the Arc Flash phenomenon, the hazard involved, and methods the relay engineer can use to positively impact the safety of personnel who must operate and maintain energized electrical equipment.

II. Definition of Arc Flash and Related Terms

Arc Flash hazard: a dangerous condition associated with the release of energy caused by an electric arc. [1]

Electric hazard: a dangerous condition in which inadvertent or unintentional contact or equipment failure can result in shock, Arc Flash burn, thermal burn, or blast. [1]

Flash protection boundary: an approach limit at a distance from exposed live parts within which a person could receive a second-degree burn if an electrical Arc Flash were to occur. The incident heat energy from an arcing fault falling on the surface of the skin is 1.2 calories/cm2 (See Fig. 1). [2]

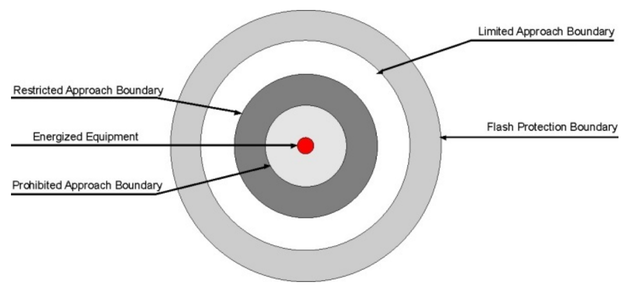

Fig. 1. Flash Protection Boundary

Incident energy: the amount of energy impressed on a surface, a certain distance from the source, generated during an electrical arc event. One of the units used to measure incident energy is calories per centimeter squared (cal/cm2). [2]

Limited approach boundary: an approach limit at a distance from an exposed live part within which a shock hazard exists. [2]

Qualified person: one who has skills and knowledge related to the construction/operation of the electrical equipment and installations and has received safety training on the hazards involved. [2]

Restricted approach boundary: an approach limit at a distance from an exposed live part within which there is an increased risk of shock, due to electrical arc over combined with inadvertent movement, for personnel working in close proximity to the live part. [2]

Prohibited approach boundary: an approach limit at a distance from an exposed live part within which work is considered the same as making contact with the live part. [2]

Working distance: the dimension between the possible arc point and the head and body of the worker positioned in place to perform the assigned task. [1]

Thus, the Flash Protection Boundary becomes an important approach distance from live equipment within which qualified personnel must wear protective clothing and equipment and within which unqualified personnel are prohibited.

An exposure to 1.2 calories/cm2 would normally result in a curable second-degree burn. Within this boundary, workers are required to wear protective clothing like fire resistant (FR) shirts and pants and other equipment to cover various parts of the body.

The flash protection boundary distance varies with the type of equipment used. It is primarily a function of the available voltage and fault current of the system at that point, and the tripping characteristics of the upstream protective device.

TABLE I
CATEGORIES OF PPE (PERSONAL PROTECTIVE EQUIPMENT) AS DESCRIBED IN NFPA 70E

Category	Cal/cm^2	Clothing
0	1.2	Untreated Cotton
1	5	Flame retardant (FR) shirt and FR pants
2	8	Cotton underwear FR shirt and FR pants
3	25	Cotton underwear FR shirt, FR pants and FR coveralls
4	40	Cotton underwear FR shirt, FR pants and double layer switching coat and pants

III. ARC FLASH HAZARDS

An electric arc, or arcing fault, is a flashover of electric current through the air from one live conductor to another or to ground. An Arc Flash hazard is the danger that comes from the heat energy generated in an Arc. Electric Arcs produce intense heat, sound blast and pressure waves, and can ignite clothing, causing severe burns that are often fatal.

The demand for uninterrupted power has created the need for electrical workers to operate and perform maintenance work on exposed live parts of electrical equipment. This creates a hazard from potential electric shock. The electric shock hazard has been addressed in electrical safety programs since electricity use began. However, only recently has the hazard brought about by Arc Flash been prominently addressed.

A. Hazards of Arcing Faults

Heat – Fatal burns can occur when the victim is several feet from the arc. Serious burns are common at a distance of 10 feet [3].

Objects – An Arc sprays droplets of molten metal at high-speed and blasts shrapnel that can penetrate the body.

Pressure – Blast pressure waves have thrown workers across rooms and knocked them off ladders.

Clothing – can be ignited several feet away. Parts of the body covered by burning clothing can be burned much more severely than exposed skin.

Hearing Loss – Sound from the Arc can have a magnitude as high as 140 db at a distance of 2 feet from the arc [4].

B. Frequency and Seriousness of Arc Flash Injuries:

Although it may appear that Arc Flash incidents are uncommon, statistics show that the damage they cause is considerable. The U.S. Bureau of Labor Statistics data for 1994 showed 11,153 cases of reported days away from work due to electrical burns, electrocution / electrical shock injuries, fires and explosions.

Daily, in the United States, an average of five to ten people are sent to special burn units due to Arc Flash burns. “There are one or two deaths per day from these multi-trauma events,” said Dr. Mary Capelli-Schellpfeffer, principal investigator, CapSchell, Inc., a Chicago-based researching and consulting firm specializing in the prevention of workplace injuries and death [5].

IEEE Standard 1584, IEEE Guide for Performing Arc Flash Hazard Calculations, provides 49 Arc Flash injury case histories in Annex C. A brief description is provided for each case on incident setting, electric system, equipment, activity of worker, event apparel worn by the worker and the outcome of the incident. Readers are encouraged to review these case histories to gain insights into various conditions leading to Arc Flash injuries.

C. Applicable Standards

There are several standards that identify requirements related to working with live electrical parts and specifically, Arc Flash protection. Some standards are OSHA (Occupational Safety and Health Act) 29 Code of Federal Regulations (CFR) Part 1910 Subpart S, NEC (National Electrical Code) 2005 NFPA 70, NFPA (National Fire Protection Association) 70E Standard for Electrical Safety in the Workplace 2004 Edition, IEEE Standard 1584 2002 Guide for Performing Arc Flash Hazard Calculations, and NESC 2007 (National Electric Safety Code). While a summary of several applicable standards is included in this paper, refer to each standard for the specific scope and specific application of the standard. In some cases, the standard applies to industrial or commercial electrical systems and not utility electrical systems. Further, the adoption of a standard and regulation will depend on the electrical system's location. [6]

D. OSHA Title 29 Code of Federal Regulations Part 1910 Subpart S:

OSHA's function is to regulate practices in the workplace for both the employer and the employee. Included in these practices is one to prevent electrical shock or other injuries that could result from coming in contact with live electrical parts either directly or indirectly. OSHA requires that for work to be performed on electrical parts, the parts must be de-energized, locked out and tagged as such, except for special circumstances. If de-energizing the electrical part is not possible because continuity of service is required or if de-energizing it would create other hazards, then OSHA will allow work to be carried out on the live electrical parts.

E. NEC 2005 NFPA 70E

The NEC is utilized mainly for design, construction, installation, and inspection. For example, it identifies the required clear working space around live electrical parts. The standard is very detailed and complex. The standard does identify specific requirements for Arc Flash protection. It requires that electrical panels, enclosures, etc. that would typically require access while energized be marked with signage warning qualified personnel of potential electric arcflash hazards. This signage is to be in plain view of qualified personnel prior to work being performed. The standard references the NFPA 70E standard for further specific measures.

F. NFPA 70E Standard for Electrical Safety in the Workplace 2004

This standard provides specific details on working with electrical parts. It identifies the definition of a qualified person who plans to work on the electrical parts, the need for an Electrical Safety Program and Procedures, and the need for a Hazard/Risk Evaluation Procedure. It goes on to identify specific steps and identifies practices for working on or near live parts. This includes specific information on the appropriate boundary requirements and personal protective equipment necessary in order to minimize the possibility of electrical shock or injury. This document references the IEEE Standard 1584 for further details.

G. IEEE Standard 1584 Guide for Performing Arc Flash Hazard Calculations

This standard provides calculation details for the Flash Protection Boundary, the required level of PPE, and the anticipated incident energy level.

H. National Electrical Safety Code Standard C2-2007

This standard covers basic provisions for safeguarding of persons from hazards arising from the installation, operation, or maintenance of (1) conductors and equipment in electric supply stations and (2) overhead and underground electric supply and communications lines. Per Section 41, paragraph 410.A.3, effective as of January 1, 2009, the employer shall ensure that an assessment is performed to determine potential exposure to an electric arc for employees who work on or near energized parts or equipment.

I. CSA Z462Arc Flash Safety Standard

This is a Canadian standard that covers many issues addressed by NFPA 70E. [6]

IV. How to Determine Arc Flash Energy and the Flash Protection Boundary

NESC 410 provides tables for determining protective clothing systems, but Arc Flash calculations provide a more precise method and should be used whenever possible. There are several things to consider when calculating incident energy and the flash protection boundary such as theoretically-derived equations and empirically-derived equations. Other considerations are voltage level, conductor separation, open air operation, enclosed operation, and the size of the enclosure.

There are computer programs on the market that do a very good job of calculating Arc Flash energy and the Arc Flash protection boundary in general as part of an overall short circuit study. Some of the better ones will calculate the answers using several methods, giving a range of outputs for Arc Flash energy and the distance to the "Flash Protection Boundary". They also will print OSHA required safety signs. It is recommended that one of the computer programs be utilized in an Arc Flash study.

In this paper, Ralph Lee's equations are utilized to illustrate the necessary principles, although these equations are considered accurate only at 15 kV and above. IEEE 1584 takes into account other factors for lower voltages which make the answers a bit more accurate than the Ralph Lee equations but generally follow the same principles. Ralph Lee's equations allow the relay engineer to understand the following discussion and to make informed decisions in design and application. [3]

$$E = 2.142 * 10^6 * V * I_{bf} * t \; / \; D^2 \tag{1}$$

$$D_B = \mathrm{Sqrt}\,(2.142 * 10^6 * V * I_{bf} * t / E_B) \tag{2}$$

Where:

E	=	incident energy (J/cm2)
D_B	=	distance of the Flash Protection Boundary from the arcing point (mm)
V	=	System Voltage L-L (kV)
I_{bf}	=	bolted fault current (kA)
t	=	arcing time (seconds)
D	=	distance from possible arc point to person (mm)
E_B	=	incident energy in J/cm2 at the boundary distance

As seen in the above equations, the incident energy is directly proportional to the Voltage level, the Bolted fault current level and the duration of the arc (time). It is inversely proportional to the square of the distance of the person from the arc.

V. Reducing Incident Energy Exposure to Personnel

From the incident energy equation above, mathematically there are four factors that reduce arc fault energy levels:

- Lower the *voltage*
- Lower the *fault current*
- Lower the *duration* of the arc (time)
- Increase distance from the energized conductors.

Voltage Levels: Once an electrical installation is completed, there is very little the relay engineer can do to influence the operational voltage levels. Then, the voltage levels are taken as a given.

Fault Current: There is very little the relay engineer can do to influence the fault current levels after installation. In some cases where main – tie – main operations exist, the fault current will nearly double (assuming the transformer impedance is large compared to the upstream source impedance) when the tie breaker is closed with both transformers in service. The relay engineer can implement a switching requirement that the tie breaker be blocked from closing when live work is being performed downstream. This would allow for lower fault currents for the Arc Flash calculations. Additional methods that can reduce available fault current include the following:

- Tied verses Split bus operation
- Current limiting fuses
- Reduce transformer sizes
- Increase transformer impedance
- Current limiting reactors
- Electronic current limiters
- Impedance grounding

Distance from Arc: For existing facilities, Arc Flash studies are performed. Studies include the collection of all pertinent equipment data and ratings and typically are plugged into one of many good Arc Flash computer programs. Based on these results, the relay engineer can generate safe distance signs including PPE requirement, which are posted on equipment warning of Arc Flash hazards. Good Arc Flash computer programs will print the necessary signs for a particular location. See example in Fig. 2.

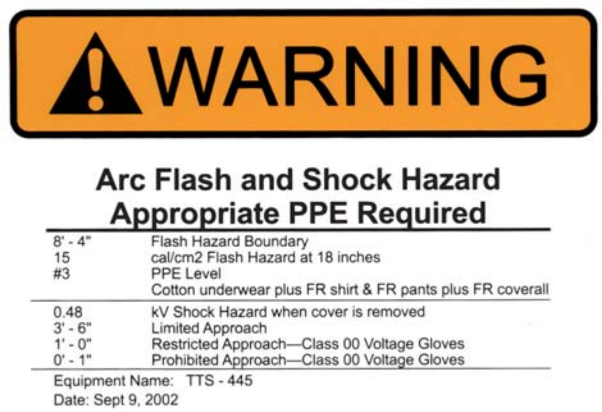

Fig. 2 Sign Example

During the facility design phase, "distance to arc" can be mitigated by proper placement of protection and control equipment i.e. locating protective relays and control switches remote from the primary equipment. For rack mount breakers, remote racking techniques can be utilized to put distance between the potential arc source and the operator. Also, arc resistant switchgear can be utilized. Some switchgear is designed to withstand the blast of an Arc Flash, including stronger doors and structures as well as providing a venting path for Arc Flash energy away from personnel working areas. Typically, arc-resistant switchgear includes circuit breakers with high speed clearing times typical of the molded case breaker listed below under breaker clearing times. [8].

Therefore, "distance from arc" methods used to mitigate Arc Flash energy include the following:

- Post required signs warning of Arc Flash boundaries
- Locate relays and control handles away from protected equipment
- Remote racking
- Arc resistant switchgear
- De-energize equipment for maintenance

Duration of Arc: The fourth variable t, the arcing time, can be influenced a great deal by the relay protection engineer. Typical protection coordination studies depend on time and magnitude of fault current to provide coordination between upstream and downstream devices. However, for Arc Flash conditions, time is the enemy and, the longer a fault persists, the higher the incident energy becomes. *A low* *fault current event allowed to persist could have more Arc Energy (incident energy) than a high magnitude fault current that clears quickly.* Protection strategies that reduce clearing times for Arc Flash conditions greatly reduce the incident energy and the overall impact of the event.

Breaker Clearing Time: is another factor that adds to fault clearing time. These are some typical breaker clearing times:

- 1.5 cycles < 1kV molded case
- 3.0 cycles < 1kV power circuit
- 5.0 cycles 1 – 35 kV
- 8.0 cycles > 35kV

VI. Relaying Techniques to Reduce Arc Flash Energy

In all protection schemes, the boundary of the zone of protection is defined by the location of the CT. Traditionally, switchgear has been designed to allow CT installation on the bushings of the circuit breakers. This provides a convenient location for the installation of the CTs and provides good physical protection of the CTs (See Fig. 3). Also, at this location there are no concerns of cable shields interfering with proper measurement of the current. As pointed out above, this location can create the situation of faults within the switchgear being seen as beyond the zone of the switchgear. If the CTs are moved to the cable compartment, the zone of protection can be extended to include the cable terminations.

Unfortunately, in this location it will be necessary to provide support for the CTs, run the cable shields back through the CT to cancel any current flowing on the shield, and find a path for the CT secondary circuit from the cable compartment to the control compartment. Keeping this in mind, there are several techniques that can be utilized to reduce Arc Flash energy.

- Enable sensitive Instantaneous Overcurrent Elements During Maintenance
- Single function relays with two instantaneous overcurrent elements
- Numeric relays, multiple inst elements or change Setting Groups
- Relays with instantaneous element supervised by arc or noise detection
- Fast Trip Schemes using Relays and Communications
- Multifunction phase and ground overcurrent relays, up and down stream blocking
- Low impedance differential blocking
- Bus interlocking Protection
- Current Differential Relay Protection
- High impedance bus differential protection
- Low impedance bus differential protection
- Reduce Coordination Intervals of existing time overcurrent relays
- Breaker Failure Protection

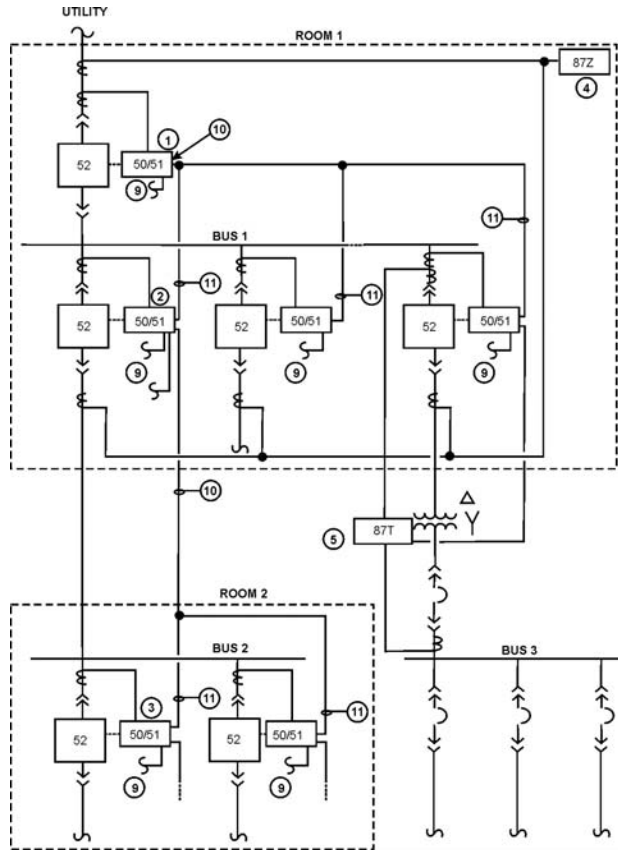

Fig. 3. Industrial System

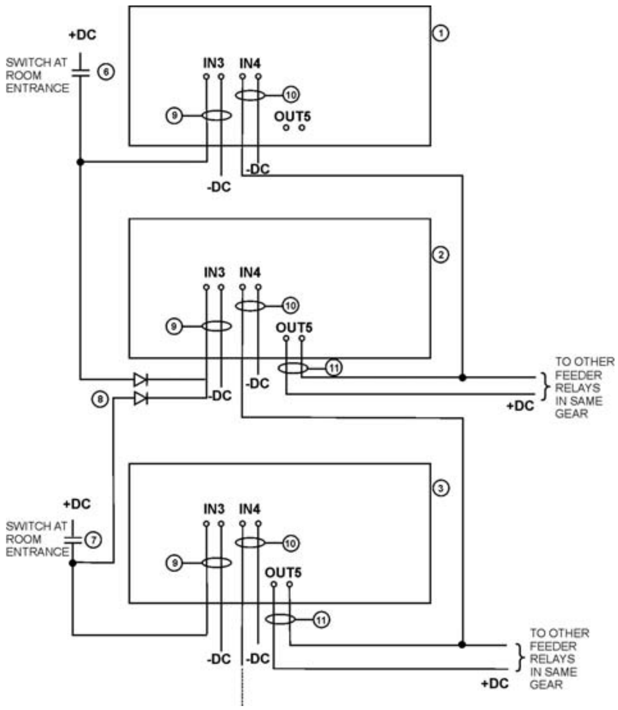

Fig. 4. Relay Connection

LEGEND, Figures 3 and 4

1. Multifunction Relay at main breaker
2. Multifunction Relay at feeder breaker in main board
3. Relay at feeder breaker in sub-board.
4. High Z Bus Differential Relay.
5. Low Z Transformer Differential Relay.
6. Contact of switch at entrance of Switchgear Room.
7. Contact of switch at entrance of Switchgear Room.
8. Diodes used to allow two switches to control the same relay input without mixing signals.
9. Connections to relay from switch at room entrance.
10. Blocking signal input to relay room downstream relays.
11. Blocking signal output from relay to upstream relay.

A. *Enable Sensitive Instantaneous Elements During Maintenance*

This method is discussed first, because it has one of the fastest clearing times of all of the methods, while at the same time it is usually the least expensive method for solving Arc Flash issues in existing installations.

TABLE II
ADVANTAGES, DISADVANTAGES AND TYPICAL COST

Advantages	Disadvantages	Typical Cost
Fast response – 1.5 cycles plus breaker clearing time	Selectivity and coordination is lost while in maintenance mode	1. 43 switch and wiring 2. external reclose block switch and wiring 3. replacement relays Cost Range $200 to $3,000
Voltage application • transmission • distribution • industrial • radial feeds only	Changes must be made to operating and maintenance procedures	
Use existing main and feeder overcurrent relays and distribution line reclosers	Some relays go off line while setting groups change, providing no protection during that time	
Low cost plug and play replacement of older relays	Limited to use with radial systems	
Low cost to install control switch and wiring		

TABLE III
BREAKER FAILURE ISSUES

Protection	Backup Methods	Issues
Any radial scheme	• Allow upstream relays to time out and trip upstream breaker	• Can take seconds to clear fault • No additional cost
Legacy 50/51 relays. Add breaker failure relay. Multifunction relays without breaker failure scheme. Add breaker failure relay. Multifunction relays with breaker failure scheme. Utilize existing breaker failure scheme.	• Retrip to failed breaker using primary and/or secondary trip coil • Trip upstream device with some transfer trip scheme and reclose blocking • Trip 86 device that clears upstream bus and reclose blocking	• Can clear fault in 20 cycles or less • Cost to purchase and install breaker failure relay • Cost to install transfer trip scheme wiring or circuit

This method reduces arc duration by forcing the feeder breaker protection to miscoordinate as a result of increasing the sensitivity of the instantaneous (50) pickup setting at the feeder breaker. Miscoordination occurs for the short period of time maintenance is being performed on the energized circuit. This allows the circuit to trip in the fastest possible time while electrical workers are in the Flash Protection Boundary. Generally, this is referred to as putting the system in "maintenance mode". Remember, the goal of this program is to give the workers maximum protection and to reduce the amount of Arc Flash clothing required so they can safely perform their work with minimum impediment.

Typically, a system using numeric relays has multiple instantaneous (inst) units and multiple settings groups. This provides several options for using a sensitive inst element or an alternate setting group for Arc Flash mitigation without the need for additional relays. Also, the majority of electromechanical overcurrent relays with a single inst element now have "plug and play" options available that include a second, sensitive inst element. Either of these solutions produces a similar result in that a second sensitive inst element is switched in during "maintenance mode" operation, providing high speed tripping over the length of the circuit (mis-coordinating). For normal operation, fully coordinated inst protection is provided by a separate 50 element.

Using switches at the entrance to each switchgear room or on each substation feeder, single function or multifunction relays can have a second 50 element inserted into the circuit, or the multifunction relays can be switched to a different settings group. The switch would be wired to an input on each relay and used to control which of the settings groups or 50 elements is active. With the switch in the "normal" position, there is no change in 50 element setting. With the switch in the “maintenance mode” position, the relay will have an instantaneous element set no more than 150% of maximum load, with an allowance for any starting inrush currents that might occur while workers are performing “hot” work.

Ideally, the change in settings groups on multifunction relays or 50 elements on single function relays also would be applied to the relay of the breaker supplying the gear in question, because the reduced hazard only applies for faults beyond the CTs connected to the relay with "maintenance mode" settings applied. If the supply breaker resides in the switchgear in question, that section of the gear will not have the same lower hazard level associated with the remainder of the gear.

Figures 3 and 4 demonstrate an example of this application for setting group changes in numeric relays. In Fig. 3, note the location of Relays 1, 2, and 3; and in Fig. 4, note the connections to input IN3 of each of these relays. Relay 1 is on the main breaker on the incoming line from the utility to switchgear bus 1 in room 1. Relay 2 is in the same gear as Relay 1 and protects the feeder to switchgear bus 2. Relay 3, at switchgear bus 2, is on a feeder supplied by bus 2. [8]

A switch at the entrance to switchgear room 1 would activate IN3 on Relays 1 and 2 to change the settings groups of these relays. Unfortunately, there is no means to increase the speed of the utility protection ahead of Relay 1, so the fast tripping does not apply for faults on the supply side of the main breaker; that section will have higher incident arc energy than the remainder of the gear.

A switch at the entrance to switchgear room 2 controls Relay 3 and other relays in that gear, as well as Relay 2 in switchgear room 1 on the feeder to switchgear bus 2. To allow the control switches at each room to control Relay 2 through the same input, the diodes shown are used to block the signal from traveling beyond the intended relays. That way, when the switch for room 2 is on, Relay 3 and the other relays in that room are in the "maintenance mode" settings group, as is Relay 2 in room 1. The upper diode prevents the signal from reaching Relay 1 and other relays on that bus, leaving the coordinated protection active. One consideration when contemplating this approach is the relay’s response to the command to change settings groups. Some relays make the change from one settings group to another between 1/4 cycle scans and are never off-line. Relays from some manufacturers are known to go off-line during the time settings groups are changing, and the relay does not provide any protection during that time.

Similarly, the same coordination options found in the multifunction application can be provided for legacy applications with single phase, CT powered “plug and play” upgrade overcurrent relays. These are direct replacements (no wiring changes) for the electromechanical products, and each has a 51 time overcurrent and two 50 instantaneous overcurrent elements (50-A and 50-B). As with the multifunction option shown in Fig. 5, contacts from the Maintenance Mode switch are used for switching in the sensitive 50 element during the time personnel are maintaining energized equipment. Two contacts from the maintenance mode switch at the entrance to switchgear room 1 and two contacts from the switch at the entrance to switchgear room 2 allow for overlapping relay number 2 with relay number 1 or 3.

Fig. 5 illustrates another application using the same plug and play capabilities for replacement of legacy relays. Before maintenance crews begin work on an energized substation distribution feeder, automatic reclosing (79) is defeated by placing the recloser on/off switch (43) in the off position. This prevents automatic reclosing of the circuit breaker while the crews are working on the energized circuit. Also, a contact from the recloser on/off switch typically is used to insert the second instantaneous element (50-B) of the plug and play products.

As with the multifunction options, the 50-B minimum pickup for the plug and play application is set below the 51 pickup value, providing sensitive "high speed fault detection" for the entire circuit. As mentioned, this does cause miscoordination but only for the short period of time the crew is working on or near the hot circuit, at which time the most important thing is their safety. With the low set instantaneous element in the circuit, it doesn't matter in what part of the circuit the crew is working, they are always covered by high speed "detection", thus reducing Arc Flash energy as compared to that associated time delay tripping (51).

In either application, breaker operate time is fixed and cannot be improved by protective relay choice.

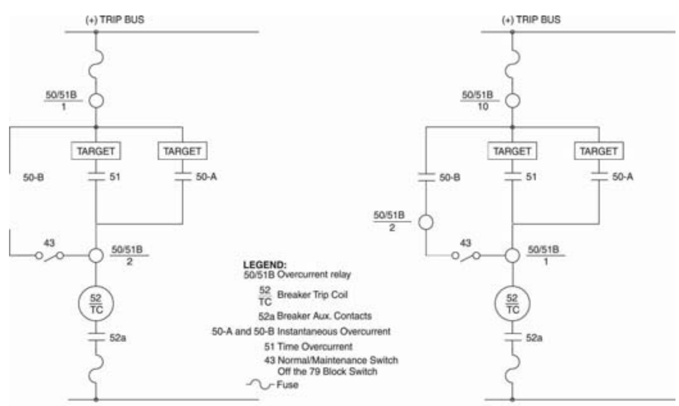

Fig. 5. “Plug & Play” relay replacements for electro-mechanical product [9]

B. *Second Instantaneous Setting Example*

By adding a second instantaneous unit when personnel are working on the circuit, the relay trip time can be reduced significantly and, thus, the Arc Flash energy. For the example in Fig. 6, we have a 1200 amp arcing fault. If the second instantaneous element were enabled, the trip time would be reduced from 42 cycles to 5 cycles plus breaker opening time. This is an 88% time reduction and equates to a reduction in Arc Flash energy from 17 cal/cm^2 to 4 cal/cm^2. This is a significant reduction, reducing the hazard from Category 3 to Category 1, which reduces the amount of protective clothing required by the worker. [9]

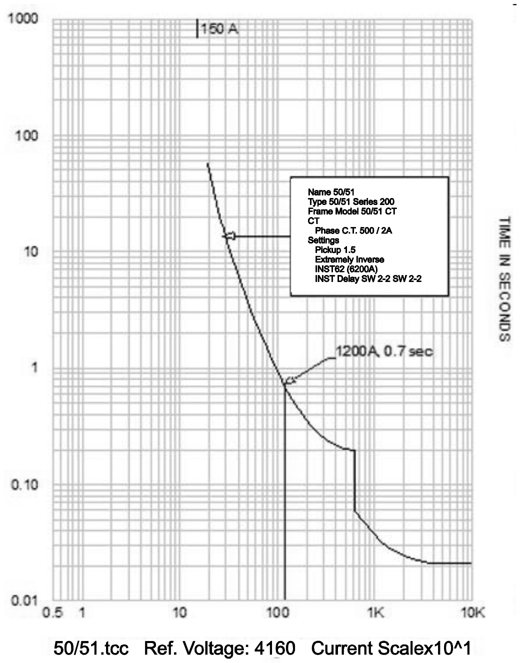

Fig. 6. 1200 Amp Arching Fault [9]

C. Securing Optical Arc-Flas Detection with a 50 Element

TABLE IV
ADVANTAGES, DISADVANTAGES AND TYPICAL COST

Advantages	Disadvantages	Typical Cost
Fast response – .5 cycles plus breaker clearing time	Cost of replacement relays with light/noise detector capability	1. Replacement relays with light detection capability 2. fiber installation Cost Range $5000 and up
Remains in service continuously	Cost of fiber installation	
	Not useful for lengthy lines at any level - industrial, distribution or transmission	

TABLE V
BREAKER FAILURE ISSUES

Primary Protection	Backup Methods	Issues
Any radial scheme	• Allow upstream relays to time out and trip upstream breaker	• Can take seconds to clear fault
Multifunction relays with light detectors and a breaker failure scheme	• Retrip to initial breaker using primary and/or secondary trip coil • Trip upstream device with some transfer trip scheme and block reclosing • Trip 86 device that clears upstream bus and block reclosing	• Can clear fault in 20 cycles or less • Cost to install transfer trip scheme wiring or communication server • Assume any multifunction relay with light detector capability also will include breaker failure function

When an arc occurs, it creates a very high-intensity light flash that can be used for Arc Flash detection. Optical sensors provide an extremely fast and clear indication that an Arc Flash has occurred. The light emitted during an Arc Flash event is significantly brighter than the normal background and easily detected using proven technology.

The light sensors are either lens-point or bare fiber-optic sensors. The light is channeled from the sensor to the protective relay threshold detector. Likewise, the lens-point sensor receives light at a single point and feeds it through a jacketed fiber optic cable to the protective relay threshold detector. The bare fiber sensor consists of a high-quality bare fiber optic cable without a jacket. This bare fiber optic cable can receive light at any point on the cable.

Light sensors should be located where arc detection by the specific sensor would trip the upstream circuit breaker. Bare fiber cables make detection in large areas possible using only one sensor. The use of lens point sensors allows better control in small, confined spaces. Proper installation of the sensors and relays provides logical detection and trip points in any system. Some have implemented Arc-detection alone, but this has proven problematic because lighting conditions, such as a camera flash near a sensor, have caused false operations.

One of the advantages of light detection is the lack of a requirement to coordinate with downstream devices and the ability to operate extremely fast (½ cycle or less).

To ensure the security of light and noise detecting schemes, the addition of an inst overcurrent element (50) in series with the light output typically is included. Together, these two methods provide an extremely fast and very secure Arc Flash detection scheme. The CT for the 50 element should be located upstream from the switchgear so it will sense current for any switchgear fault.

D. Fast Trip Schemes using Relays and Communications

TABLE VI
ADVANTAGES, DISADVANTAGES AND TYPICAL COST

Advantages	Disadvantages	Typical Cost
Fast response – typically 3 - 5 cycles plus breaker clearing time	Legacy relays must be replaced with multifunction relays	1. control wiring 2. replacement relays 3. protection logic processor Cost Range $200 to $30,000 and up depending on the number of relays to be replaced
Use of existing multifunction relays	Cost to install control wiring	
	Cost to install protection logic processor	

TABLE VII
BREAKER FAILURE ISSUES

Protection	Backup Methods	Issues
Multifunction relays without breaker failure scheme. Add breaker failure relay Multifunction relays with breaker failure scheme	• Retrip to initial breaker using primary and/or secondary trip coil • Feeder breaker relay remove block of upstream breaker • Main breaker trip upstream device and block reclosing • Trip 86 device that clears upstream bus block reclosing	• Can clear fault in 20 cycles or less • Cost to purchase and install breaker failure relay • Cost to install transfer trip scheme wiring or circuit • Can make use of logic processor if available.

Although it requires the use of numeric relays, communications among relays can greatly reduce the relay time without the need for additional relays. Again referring to Fig. 3, consider two relays on a radial circuit, one upstream of the other. In addition to the normal time and instantaneous overcurrent settings, we add an additional low set definite time (instantaneous with time delay) setting on each relay. We also connect an output of the downstream relay to an input of the upstream relay. For each relay, this new setting is set above load, for example 150% of load, but does not necessarily need to coordinate with inrush or other transient events. The upstream relay may be set less sensitively as it may serve more load than the downstream relay, or the relays may be set nominally the same if they see the same load. In no case should the upstream relay be set more sensitively than the downstream relay. To avoid inadvertent lack of coordination, the upstream relay should be set less sensitively than the downstream relay by at least twice the relay/CT tolerance. The downstream relay logic will be set to activate the output whenever the low set element is picked up. See Fig. 7.

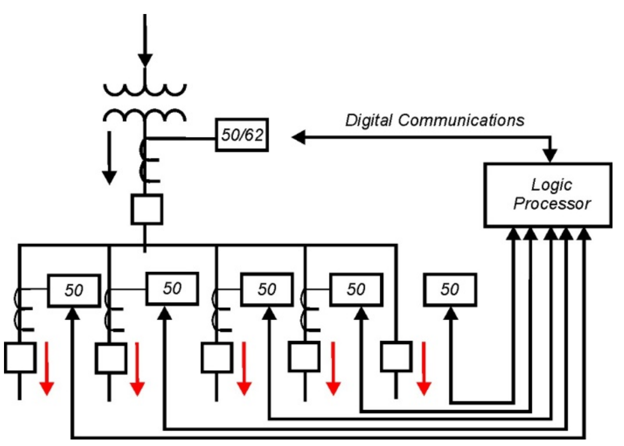

Fig. 7. Bus Interlock Scheme

The upstream relay receives, through its input, a signal that the downstream relay detects something unusual. The NOT of this signal will be ANDed with the trip of the low set element in the upstream relay.

Knowing that the fault or other abnormality is beyond the next relay downstream, the upstream relay does not need to trip. If the upstream relay low set element picks up but the blocking signal is not received, it can trip after a delay long enough to allow receipt of the blocking signal, plus some margin, because it will have been determined that the fault is located between the relays. With relays directly connected, the delay time can be 3 cycles or less; with an interposing relay, the delay time can be 4 cycles. Testing during system commissioning can determine the nominal signal time, and the protection engineer can add the desired margin to arrive at the time setting. With this technique, it is helpful to use a very short recognition time and a very long debounce time for the input on the upstream relay. The short recognition time is desired to ensure that the signal is recognized as quickly as possible, thereby allowing a shorter delay time. The long debounce time is desired to keep the blocking signal in place until after the element on the upstream relay has dropped out. Making these adjustments to the input processing times increases the security of this scheme.

The scheme can be extended to include more relays upstream and downstream of the two considered above. As with the bus differential, if this scheme is used only within one piece of switchgear, there will be very fast clearing for faults on the bus itself, but faults that occur on the cable terminals of outgoing feeders will be beyond the CTs of the downstream relay. Communications from the next switchgear or from the load will extend the scheme and provide complete protection.

This scheme is illustrated in Fig. 4. Starting with Relay 3, OUT5 closes whenever the low set picks up. This signal becomes an input to Relay 2, shown as IN4 in this example. The signal from OUT5 is paralleled with outputs of other relays at the same level in the system so that any relay can provide the blocking signal. Relay 2 receives the blocking signal from relay 3 and has sent a blocking signal upstream to Relay 1. If a fault occurred on bus 2 (Fig. 5), the low set element on Relays 1 and 2 would pick up; Relay 1 would receive a blocking signal and would not trip. Relay 3 would not see the fault current, so no blocking signal would be sent to Relay 2, resulting in a high speed trip to clear the fault. The tripping decision would be made in 3 to 4 cycles, significantly less than using coordinated time overcurrent elements.

In Fig. 3, the connection shown between the low impedance transformer differential and the upstream relay can be used similarly. An overcurrent element operating on the CTs feed from the secondary of the transformer can provide a blocking signal which indicates that the fault has occurred on the 480V system rather than somewhere between the medium voltage gear and the low voltage gear [8].

Bus Interlocking is another example of fast tripping schemes using numeric relays and communications as illustrated in Fig. 7. This digital processor can communicate "block" and "trip" signals between relays. Alternately, these signals can be hardwired between relays using relay inputs and outputs.

E. Current Differential Relaying

TABLE VIII
ADVANTAGES, DISADVANTAGES AND TYPICAL COST

Advantages	Disadvantages	Typical Cost
Fast - less than .5 cycles	High cost to install	Beyond the scope of this paper
Secure for any fault type		
Can be applied for transmission, distribution, and industrial voltages		

TABLE IX
BREAKER FAILURE ISSUES

Protection	Backup Methods	Issues
Breaker failure for Bus Differential Schemes	• Can be extremely complex	• Beyond the scope of this paper
Breaker failure for Line Differential Schemes	• Retrip to failed breaker using primary and/or secondary trip coil • Trip upstream device with some transfer trip scheme and reclose blocking • Trip 86 device that clears upstream bus and reclose blocking	• Can clear fault in 20 cycles or less • Cost to purchase and install breaker failure relay • Cost to install transfer trip scheme wiring or circuit

In many cases, the greatest reduction in Arc Flash hazard can be achieved through the use of differential relays. The beauty of differential relaying from an Arc Flash mitigation standpoint is that it is extremely fast. Each differential relay protects a clearly defined zone within the system and does not require any delay to coordinate with protection for other portions of the system.

Bus differential protection, such as that provided by a high impedance bus differential relay, provides a means to respond to faults on a bus without the need for any delay to coordinate with other portions of the system; trip decisions can be made in less than one cycle from the onset of the fault to the trip contact closing. With the addition of breaker time, a bus fault can be cleared in 6 cycles or less (0.10 sec at 60 Hz). This is a vast improvement over conventional overcurrent protection times that can extend into the seconds or even tens of seconds.

Dedicated CTs are required for this scheme because all of the CT inputs are paralleled and then connected to a high impedance input in the relay. The relay measures the voltage across its internal impedance—typically about 2000 ohms. The relay is set such that, for the external fault, the voltage measured across the impedance is less than the pickup, and the internal fault is above the pickup. This scheme is fast and secure but relatively costly because of the need for the dedicated CTs and the additional wiring and testing required to validate the scheme. Fig. 8 shows a connection for a high-impedance bus differential scheme. The arrows show the direction of load current for a radial system. Not shown in the diagram is the tripping connection between the relay and the breakers in the gear. Typically, that tripping connection is through a lockout relay with a trip contact for each breaker.

One caution when using bus differential for Arc Flash mitigation with metal clad switchgear is that, with the CTs mounted on the breaker bushings, as in the typical installation method, the zone of protection ends at the CTs and a fault at the line terminals will not be cleared by the bus differential.

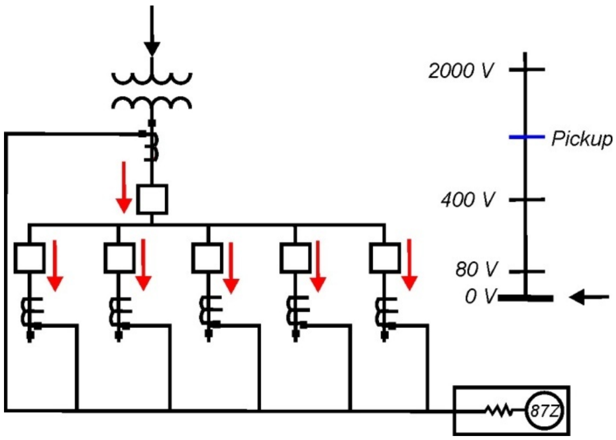

Fig. 8. High-Impedance Bus Differential Scheme

Low impedance transformer differential relays can be useful in Arc Flash hazard mitigation, particularly if the zone of protection is expanded from the usual zone of protection. Often, transformer differential relays are applied with the CTs at the terminals of the transformer, and this limits the zone of protection to the transformer itself. If, on the other hand, the CTs of the transformer differential are installed at the breakers on each side of the transformer, the zone of protection will extend to the switchgear. With the transformer differential CTs on the bus side of the breakers and the bus differential CTs on the line side of the breakers, the zones overlap and there are no locations where a fault could persist for longer periods of time while waiting for a time overcurrent element to time out. Figure 3 shows a low impedance differential relay (Relay 5) around the transformer, with the CTs located at the gear at each end of the circuit.

In many industrial installations, lines are short enough that two terminal differential relays can be used for line differential with the CTs at both ends of the line brought to the relay. Used this way, careful analysis of the burden of the CT circuits can help avoid CT saturation. The relay burden is low enough that the burden seen by the CT secondary is essentially the impedance of the conductors to the relay. If the low impedance differential shown around the transformer in Fig. 3 is connected on the feeder between the two pieces of switchgear, faults on the feeder can be cleared instantaneously.

The low impedance bus differential scheme is fast and secure and does not require dedicated CTs (i.e., additional relays, meters, transducers, etc. can be connected to the same set of CTs). Relay settings are slightly more complex than a high-impedance differential scheme because each input has an independent CT ratio and connection. Like the high impedance scheme, this scheme requires some additional commissioning testing. For the fault shown in Fig. 9, the differential scheme should not trip.

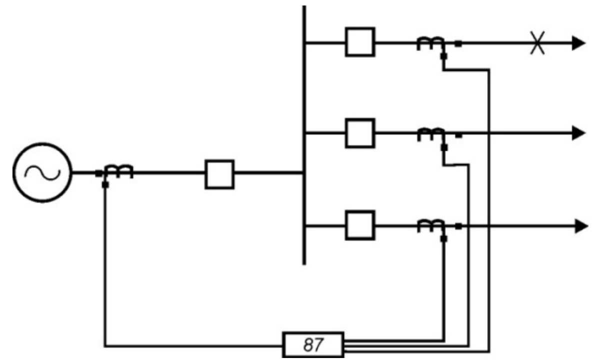

Fig. 9. Low-Impedance Bus Differential Scheme

F. *Reduce Coordination Intervals of existing Time Overcurrent Relays*

TABLE X
ADVANTAGES, DISADVANTAGES AND TYPICAL COST

Advantages	Disadvantages	Typical Cost
No capital cost	Cost of coordination study	1. Coordination study Cost Range $1000 and up
Can be applied for transmission, distribution, and industrial voltages where radial feeds are utilized	Trip times likely to remain high, in the range of .5 to 2 or more seconds	
Use existing protection hardware	Only marginal improvement can be achieved	

TABLE XI
BREAKER FAILURE ISSUES

Protection	Backup Methods	Issues
Any radial scheme	• Allow upstream relays to time out and trip upstream breaker	• Can take seconds to clear fault • No additional cost
Legacy 50/51 relays. Add breaker failure relay Multifunction relays without breaker failure scheme. Add breaker failure relay Multifunction relays with breaker failure scheme. Utilize existing breaker failure scheme	• Retrip to failed breaker using primary and/or secondary trip coil • Trip upstream device with some transfer trip scheme and reclose blocking • Trip 86 device that clears upstream bus and reclose blocking	• Can clear fault in 20 cycles or less • Cost to purchase and install breaker failure relay • Cost to install transfer trip scheme wiring or circuit

Fig. 10 shows a typical coordination of feeder relays. Most engineers and many software programs use a 0.3 second minimum coordination interval (CI) among tripping characteristics of series-overcurrent devices. A direct and simple way of reducing tripping times is to reduce coordination intervals that exceed 0.3 seconds. Most engineers do not recommend a margin of less than 0.3 seconds unless very specific testing and analysis is performed.

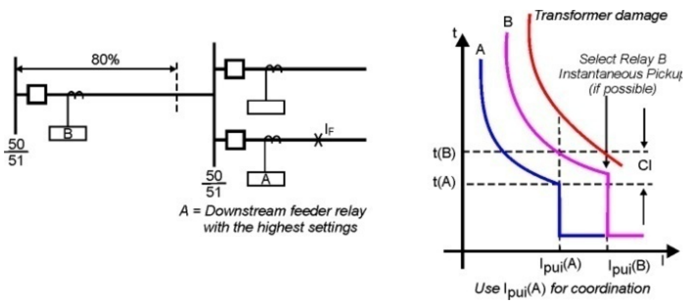

Fig. 10. Time Current Coordination

Note that setting an instantaneous overcurrent at B is desired (e.g. 125% of maximum fault current at A), but instantaneous element coordination is not possible if there is no difference in the fault current at A and B.

Fig. 11 shows fault current and relay-operate times based on fault location. We can see that fault current is highest at the source. If the distance between coordinating devices is low, the effect is that the "delta Ts" continue to add. Thus, the result is that the highest fault currents and longest trip times are closest to the source, where maintenance personnel are most likely to be working.

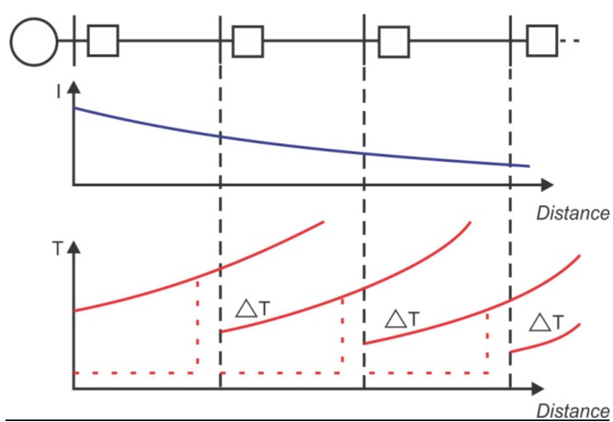

Fig. 11. Fault Current and Operate Time as a Function of Electrical Distance for Source

For some systems, it may be possible to lower pickup settings; thus, reduce trip times by applying voltage-restrained or voltage-controlled overcurrent protection.

The time overcurrent relay settings can be lowered to minimum coordination intervals, which has the advantage of using existing relays and no requirement for electrical design changes. The disadvantages are the cost of the coordination study and field setting application; often, only a small decrease in trip times may be achieved, resulting in little or no reduction in Arc Flash energy. [3].

VII. Breaker Failure Protection

All of the protection ideas discussed to this point assume that the intended breaker will trip at the proper time, but what happens if this assumption is false? The possibility of a breaker failing to trip is accounted for in conventional coordinated time overcurrent settings where each device is backed up by all devices further upstream. Failure of one device to clear a fault means that the *next* device will have an opportunity to clear the fault after the set time delay. The fact that times for this backup protection can get into the seconds becomes a serious issue if failure of one interrupting method is considered when evaluating Arc Flash hazard.

Using the breaker failure protection features of modern numeric relays, it is possible to have backup protection operate within a few cycles of a breaker failure rather than a few seconds. Referring to Fig. 3, if Relay 3 sent a trip signal to its breaker, but the breaker failure logic of the relay indicated that the breaker did not open to interrupt the current, the relay would try to retrip the breaker. Simultaneously, or with a user-selected delay, it also would send a trip signal to the breaker associated with Relay 2 to clear the fault at that location. Using breaker failure protection, the breaker at Relay 2 will be tripped to clear a fault beyond the faulted breaker at Relay 3, and that tripping can occur with a delay of less than 20 cycles after the initial attempt to trip the breaker at Relay 5.

VIII. Conclusion

With faster clearing time, the Arc Flash analysis may indicate that a lower level of PPE is required. Relay response time is only a portion of the total fault clearing time—the circuit breaker interrupting time must be added to the tripping time to get the total clearing time.

Arc Flash hazards are separate and distinct from shock/ electrocution hazards and must be addressed with appropriate work practices and personal protective equipment. The degree of the Arc Flash hazard depends on the available short-circuit current, the clearing time of the protective devices, and the working distance from the potential arc location. The level of protection required depends on the degree of hazard. Remember, the goal of this program is to give workers maximum protection and reduce the amount of Arc Flash clothing they need to wear.

Historically, protection systems have relied on time coordinated overcurrent protection for selective clearing of system faults. The need for selectivity has resulted in clearing times that become progressively longer the farther upstream in a system the fault occurs. When Arc Flash hazards are considered, this increased time results in increased levels of required PPE, until the hazard becomes so great that there is not an adequate level of PPE available.

Using the relaying techniques discussed herein, and including the breaker failure protection features of modern numeric relays, it is possible to significantly reduce the clearing time for faults at any location in the system while maintaining full selectivity. It is a realistic goal to achieve primary clearing times of less than 10 cycles and backup clearing times of less than 20 cycles for an entire system while maintaining full selectivity for all primary protection.

IX. References

[1] IEEE Standard 1584-2002, IEEE Guide for Performing Arc Flash Hazard Calculations.

[2] NFPA 70E, Standard for Electrical Safety in the Workplace, 2004 Edition.

[3] Ralph Lee, "Pressures Developed by Arcs", IEEE Transactions on Industry Applications, Vol. IA-23, No. 4, July/August 1987, pages 760-764.

[4] Ray A. Jones, et al, "Staged Tests Increase Awareness of Arc Flash Hazards in Electrical Equipment", IEEE Transactions on Industry Applications, Vol. 36, No. 2, March/April 2000, pages 659-667.

[5] L.K. Fischer, "The Dangers of Arc Flash Incidents," Maintenance Technology, February 2004.

[6] IEEE Working Group Report to the Substation Subcommittee of the PSRC, "Protection Considerations to Mitigate Arc Flash Hazards", January 2009.

[7] Ralph Lee, "The other Electric Hazard: Electric Arc Blast Burns", IEEE Transactions on Industry Applications, Vol. IA-18, No. 3, May/June 1982.

[8] Basler Electric Application Note "PC-ArcFlash", June 2006.

[9] Basler Electric Application Note "PC-ArcFlash2", September 2008.

[10] W.A. Brown and R Shapiro "A Comparison of Arc Flash Incident Energy Reduction Techniques Using Low-Voltage Power Circuit Breakers."

[11] Institute of Electrical and Electronics Engineers. 2006. "National Electrical safety code C2-2007 (NESC)". New York: Institute of Electrical and Electronics Engineers.

[12] "Add Trip Security to Arc Flash Detection for Safety and Reliability", Mark Zeller and Gary Scheer, October 2008.

X. Biographies

Johnny Simms is a Senior Application Engineer for Basler Electric Company and is based in Charlotte, North Carolina. Prior to joining Basler, Johnny spent 25 years with Duke Power Company and 10 years as a consultant. He received a BSEE from the University of North Carolina at Charlotte, an MBA from Wake Forest University and is a registered professional engineer in the states of North Carolina and South Carolina. Johnny has been a member of IEEE for 25 years, is a Certified Power Quality Engineer, and has done graduate work in Power Systems Electrical Engineering, Computer Science, Training, and Psychology.

Jerry Johnson is Application Engineering Supervisor for Basler Electric Company and is based in Richmond, Virginia. Prior to joining Basler in 1999, He spent 29 years in the System Protection organization of Dominion VA Power, including 12 years as Director of the System Protection Engineering. Jerry is a graduate of Virginia Commonwealth University and is a registered professional engineer in the State of Virginia. He is a senior member of IEEE, a member of the Power System Relaying Committee, a member of IEEE SCC21 Standards Coordinating Committee, and a member of the Texas A&M and Georgia Tech Planning Committee.

Basler Electric
www.basler.com

Highland, Illinois USA
Tel: +1 618.654.2341
Fax: +1 618.654.2351
email: info@basler.com

Suzhou, P.R. China
Tel: +86 512.8227.2888
Fax: +86 512.8227.2887
email: chinainfo@basler.com