

# The Importance of Backup Protection Systems: A Refresher for New Protection Engineers

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## Abstract

Reliability, Selectivity and Speed are daily terms used by power system protection engineers. Recognizing this relationship, digital protection relays available on the market today are made to achieve just that. Good system protection practices call for simplicity and respond correctly to all contingencies. This paper will focus on local breaker failure protection, covering the basics and enhancements of BF detection available in most today digital relays. The paper will briefly discuss the types of HV circuit breaker failures as measured from the field, collected and organized by CIGRE and IEEE working groups. These measurements have prompted protection engineers around the globe to find ways to increase the power service continuity and to minimize system and equipment damages during breaker failure contingency.

## 1 Introduction

In the past, clearing an unclear bus and line faults, resulted from a “stuck closed” circuit breaker have relied on remote back-up protection systems. These type of protection practices have caused unwanted blackouts and damages to primary connected equipments from long delay and lack of operations. Because of the rapid changing in the power demand prompts for the shortest critical fault clearing time possible on the system in order to maintain system stability and continuing services to customers. This calls for the use of local breaker failure back-up protection, since it is fast, simpler and more reliable.

Unclear faults on power system can result from the followings:

- Bad relaying principles and practices.
- Protection relay failures.
- Failures of sensing devices – ie: CTs and VTs.
- Loss of DC supply and/or control circuits.
- Tripping coil and closing coil problems.
- Mechanical, electrical or operating failures of circuit breaker.

At or above 138kV systems, utilities normally duplicate their main protection, increasing system dependability. Thus far the duplication of main protection has really provided relaying back-up in case if one system should fail. This does not cover for the failure of circuit breaker; doubling up circuit breakers is not practical and thus not mentioned here.

The following points are presented in this paper:

- Brief overview of commonly used HVCB with specs and typical CB failures and causes.
- A concept of main 1 and main 2 in HV transmission system – increasing system dependability.
- Types of back-up protection – remote and local with BF.
- Breaker Failure principles and applications applying to common bus configurations.
- Enhancements to traditional BF in coping with difficult conditions.

## 2 Common types of HVCB

A circuit breaker is defined as a mechanical device capable of making, carrying and breaking currents under both normal (load) and abnormal (short circuit) conditions for specified time period. HVCB has been evolved trying to keep pace with the system voltage and short circuit capability as a result of the growth demand of the power system. Basically, the advancements of HVCB have been surrounding the CB's interrupters designs and interrupting mediums used to extinguish the arc. In earlier HVCB, the current interrupting process changes from stretching the arc across a pair of contact to arc-chute structures and the use of magnetic blow-out coils. For indoor CB applications (5 to 38kV), air magnetic CB (US) and minimum oil CB (Europe) were quite popular in the seventies, while for

outdoor CB applications, (up to 345kV) oil and air-blast CB were very common. Later, vacuum and SF6 CB were introduced and their acceptance was excellent. HVCB can be classified into groups:

- By voltage class: Transmission and Distribution.
- By installations: Indoor and Outdoor. In practice, the differences between indoor and outdoor CB are that of the external structural packaging and the enclosures. Most of the time, the internal current carrying parts, the interrupting and operating mechanisms are similar, assuming that same voltage and current ratings and interrupting medium used.



Dead Tank SF6 CB

Live Tank SF6 CB

Figure 1

- By external design: Dead tank and Live tank. A dead tank CB has its vessel(s) which housing the interrupter(s) and insulating/interrupting medium at ground potential. A live tank CB, on the other hand has its vessel(s) housing the interrupter(s) at system voltage potential. The advantages and disadvantages between the two are usually related to which standard is being followed – ANSI or IEC. Some typical comparison is as follows:
  - Dead tank (ANSI):
    - Multiple low voltage bushing type CT can be installed at both line and load side the CB.
    - Gives high seismic withstand capability for earthquakes areas.
    - Fully assembled and calibrated at factory prior to shipping.
  - Live Tanks (IEC):
    - Lower cost since CT is normally external.
    - Less mounting space required.
    - Uses less amount of interrupting medium.
- By Interrupting mediums: Air, Oil, Vacuum or SF6.
  - Vacuum – popular in low and medium voltage (3-20kV).
  - SF6 – dominant in high voltage (72-800kV). The interrupting capability of SF6 is 100x better than air.

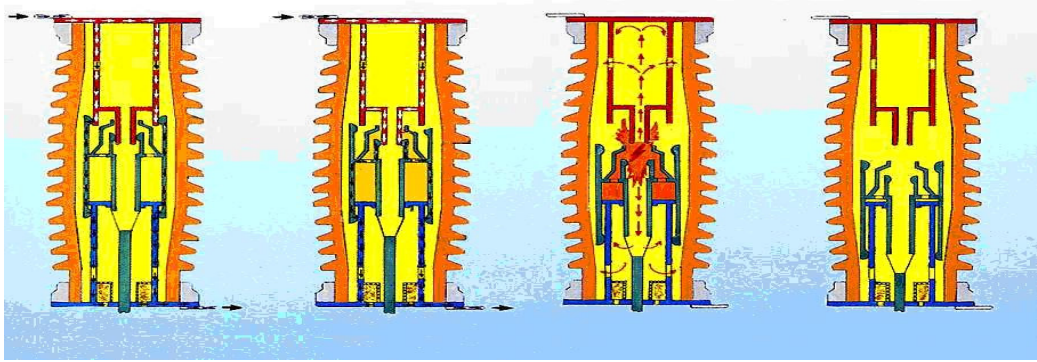


Figure 2: Main contacts parting, arc created, gas flowing, fully interrupted

Figure 3 depicts a break-down of HVCB failures studied by CIGRE working group. All failures are divided into 3 groups; 70% of failures reported in mechanical related issues, 19% in controls and auxiliary circuits and 11% in electrical in nature. Figure 4 illustrates a breakdown in details, showing the actual component failures for each group.

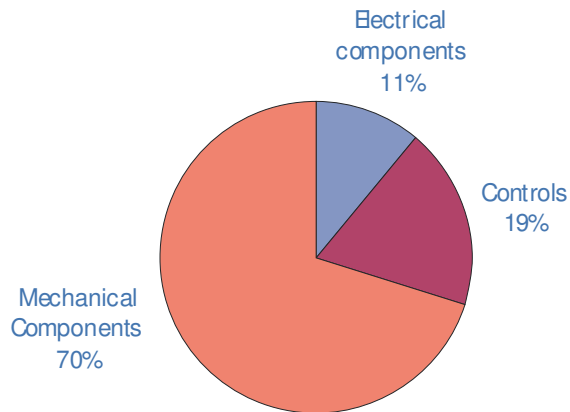


Figure 3: CB failures by major components

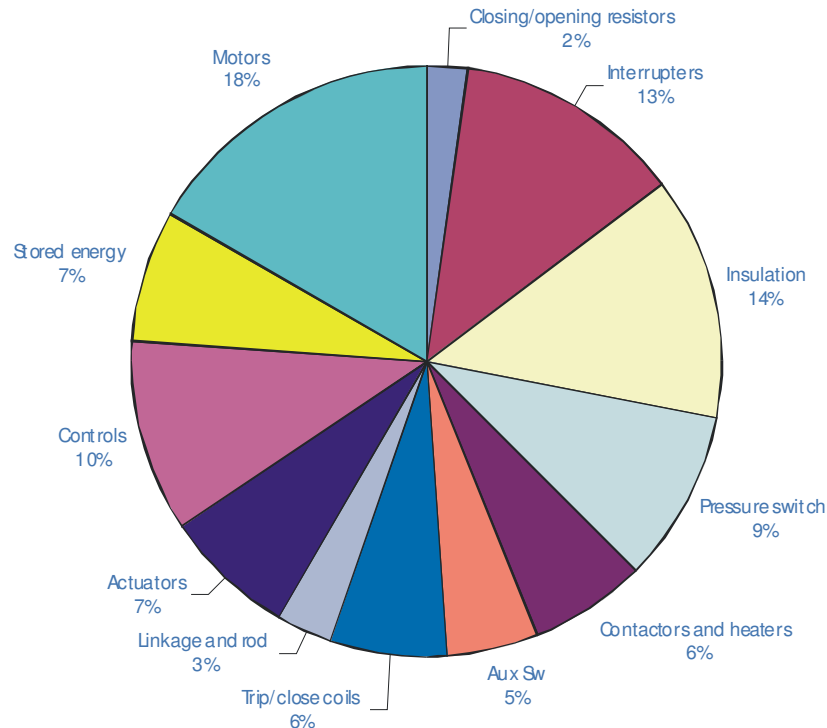


Figure 4: Breakdown in details

Circuit breakers are known as switchgear equipments and thus usually rated by the capability of making and breaking of electrical circuits. The following terms are widely used when specifying a HV circuit breaker:

- Rated RMS voltage – referring to the maximum continuous voltage (eg: 550kV for 500kV nominal)
- Rated RMS short circuit breaking current – referring to both symmetrical 3phase and 1phase (eg: 40kA). It should be noted that in some instances, single-phase to earth fault may be more destructive, exceeding the 3phase fault level by up to 20%, reported in transmission systems with multiple earthed neutrals, reducing the zero sequence impedance within the faulted loop. Table 1 System maximum fault levels, tabulating typical fault levels.

Table 1. System Maximum Fault Levels

Nominal Voltage (kV)	Fault level (MVA)	Fault level (A)
400	35000	50000
275	15000	31500
132	3500	17300
33	1000	15000
11	250	13000

- Rated duration of short circuit with CB closed – referring to the period of time for which the maximum fault current can be carried (eg: 1 second for 400 or 275kV CB, 3 seconds for 132kV).
- Maximum tripping time or interrupting time – from trip coil energized to arc extinction under rated RMS short circuit breaking current.
- Close-open time – maximum time to open if the CB is closed onto an already operated trip relay.

- Rated line and cable charging breaking current – ability to break capacitance current.
- Rated inductive breaking current.
- Continuous current rated (eg: 2000A).
- Minimum allowable re-closing time (eg: 20 cycles).

### 3 Main1 and Main2 Protection increases system dependability

The terms Main1/Main2 or Protection A/Protection B or Primary/Secondary or Primary/Backup protection systems are strictly grouped preferences used by protection engineers in the power industry. It means that there are two independent high-speed groups of protection used to safeguard section of the power system against short circuit faults. This protection practice has been accepted by utilities in many parts of the globe, applicable to 138kV and higher voltage systems.

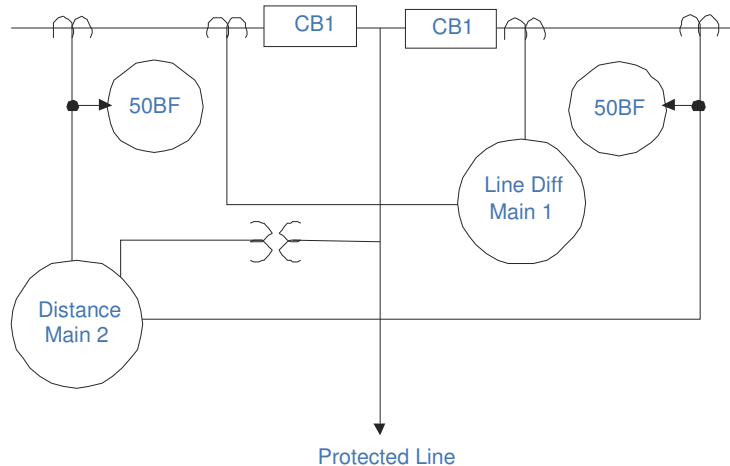


Figure 5: Main1, Main2 plus BF Backup Protections Protecting a Line

Typically Main1 and Main2 are of different types of protection principle and may come from different relays manufacturers. This is to eliminate common mode failures. Moreover, a fully redundant relaying equipments requires separate CT cores and windings, separately fused VT supplies, dual trip coils, individually fused dc control circuits (breaker trip circuit, main protective systems and BF back-up system) including redundant communication channels. It is done so that isolation of any one system, for purpose of maintenance or end-to-end testing, would not interfere other's operation. Redundant protection systems are designed to detect and clear in high speed for all short circuit faults.

HV circuit breakers do and will fail over time. High speed main protections are not meant for clearing failed breakers and thus must rely on breaker failure back-up protections. Clearing BF contingency can achieve locally or remotely. Depending on the complexity of the system configurations, interconnections, voltage level but more importantly the maximum critical fault clearance time sets out by one utility calls for either remote BF back-up or local BF back-up protection to be used. It should be kept in mind that long tripping time, larger outage and may or may not require sequential tripping are drawback inhered in remote back-up.

Table 2 Typical Clearing Times For 3phase Close-in Faults, shows typical high speed operating times at various voltage levels required by main protection. This time should include relay operating time, breaker tripping time and pilot communication delay.

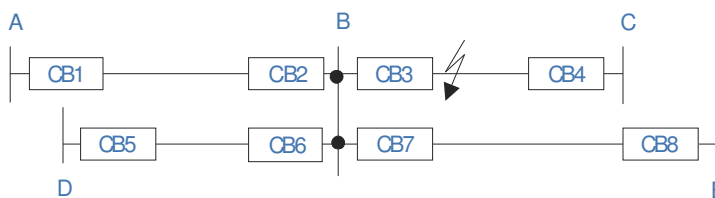
**Table 2. Typical Clearing Times for 3phase Close-in Faults**

Voltage Level	Typical Clearing Times for 3P close-in fault (~)
500kV	4
230kV	5
138kV	6

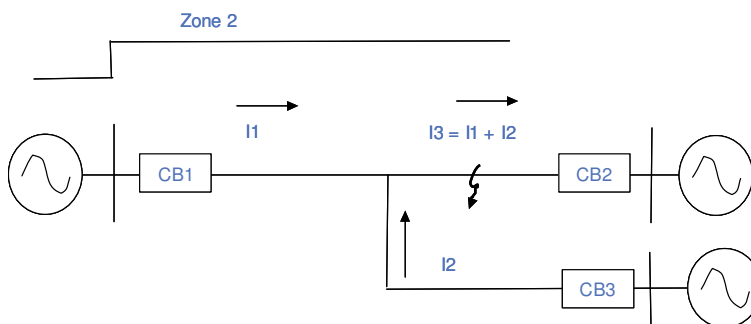
#### 4 Breaker Failure Back-up Protections

As mentioned above, main protection systems are meant for clearing short circuit faults at high speed. Breaker back-up protections are applied to isolate the failed circuit breaker; failing to clear a fault when commanding to do so. There are two types of breaker back-up protection; remote and Local.

- Remote BF back-up protection is installed at a different location and its zone of protection can overreach to other remote primary protective zones. Overreaching distance zones or time-graded over-current relays are normally employed for this purpose. Remote back-up protection can be difficult to set and coordinate with. For example, distance zone 2, 3 may have to set larger to cater for in-feed from adjacent lines. Such large reach setting may encroach into the load, in fact there have been blackouts reported that were caused by large zone3 reach. Figure7 Typical 3 Terminals System, illustrates the effect of infeed as seen by the zone2 distance protection which has set to overreach for faults beyond the tap point. The physical fault location as shown in figure 7 was within the reach of zone2. However, zone2 did not pick up, shown on figure 8 (right side) as resulted from the infeed of current  $I_2$ . On the removal of CB3, resulted from sequential tripping, brought the fault inside the zone2 reach, figure 8 (left side). For correct operation, overreaching distance zones would have to set larger in order to see for all faults beyond the tap point. Large reach creates other problems.



**Figure 6: Remote Back-up for Failure of CB3**



**Figure 7: Typical 3 terminals System**



Figure 8: Effect of Infeed as seen by Zone2

In Figure 6 Remote Back-up for Failure of CB3, a fault occurs between station B&C which typically should clear by line main protections. Assuming CB3 fails to open, remote BF backup would have to trip CB1, BC5 and CB8. This takes more lines out of service unnecessarily. Furthermore, if the fault occurs closer to station C, it may be difficult to detect by remote BF back-up because of the in-feed effect from other lines. Most of the time, clearing these faults would have to rely on sequential tripping at one remote terminal to re-distribute the fault current. Remote back-up however has higher dependability because it uses a complete 100% relaying equipments independently from that of main protections.

- Local BF back-up protection is located in the same station that also houses one of the main protection systems and so sharing common relaying equipments with that main protection.

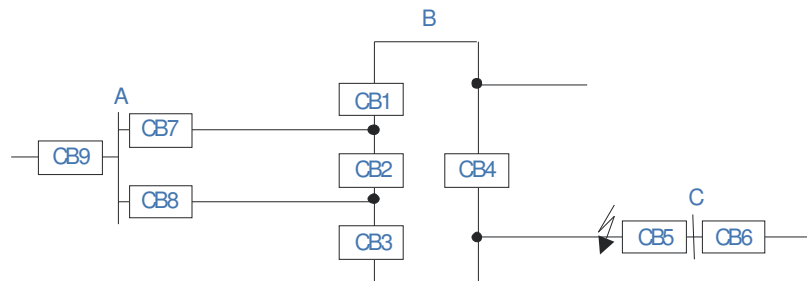


Figure 9: Use of Remote Back-up

Local BF back-up protection provides short and predictable operating times, less outage area and greater selectivity. Consider again for figure 6 Remote Back-Up for Failure of CB3, if local BF back-up protection has installed at station B, then only CB2, CB6 and CB7 would need to isolate and in much less time. Although local BF back-up has numerous benefits over remote one, but does not necessarily eliminate remote BF back-up. Figure 9 Use of BF Remote Back-up, depicts the need for remote back-up protection. A line fault, main protections operated CB5, CB4 and CB3 and initiated a BF. A failure of CB3 would cause the BF back-up protection to clear next adjacent circuit breaker, CB2. However, current would still flow through the CB8 from station A to the fault. In this case, it would need to trip CB8 from remote BF back-up protection. Please note that this line has no communication channel for DTT signal to transfer.

## 5 Breaker Failure Protection – The Basics

It is worth to keep in mind that local BF protection should bias towards system security and not speed, providing that system stability is not violated. Table3 Typical BF Clearing Times, shows typical timing requirements for clearing BF contingency.



**Table 3. Typical BF Clearing Times**

Voltage Levels	Typical BF Clearing Times(~)
500 kV	9
230 kV	10
138 kV	15

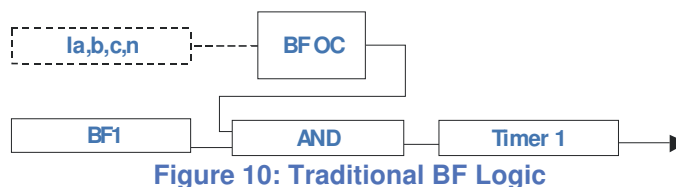
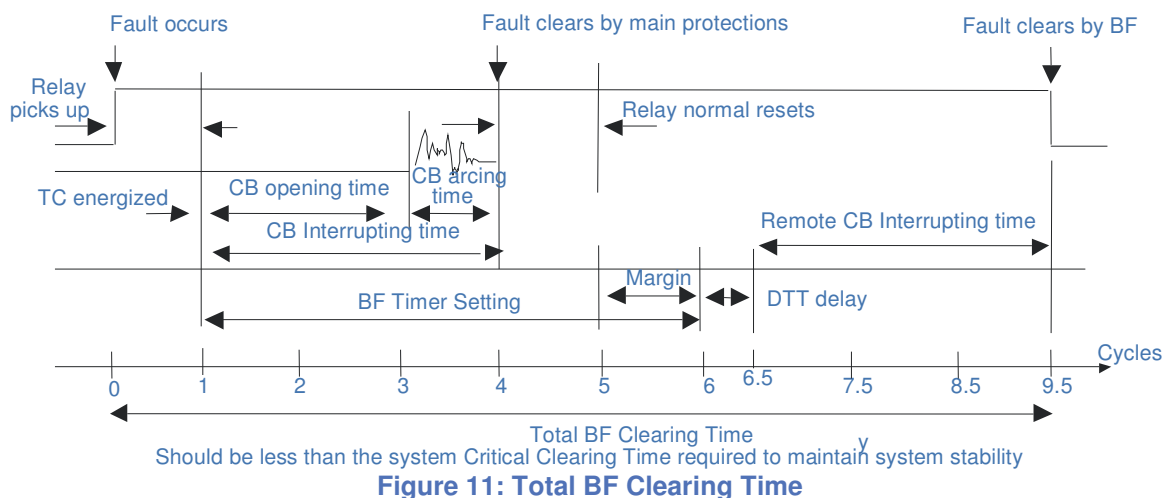


Figure 10 Traditional BF Logic, shows basic implementation of a breaker failure logic. It needs two inputs and a timer. When main protection detects fault, it initiates the BFI input. At the same time, the BF OC detector would pick up and starts the Timer1. After the expected breaker clearing time and current still flows, this implies that the breaker has failed to interrupt the fault. Thus, a BF Trip is asserted. The Timer1 setting should set greater than the normal expected breaker clearing time, refer to figure 11 Total BF Clearing Time. If primary currents are interrupted properly, the Timer 1 would stop and reset the BF logic. Either the reset of the BFI or BF OC detector would stop the BF Timer. A BF Trip should trip all surrounding circuit breakers contributing to the fault and initiates a DTT transfer trip to all remote terminals. Upon the receipt of DTT signal, additional supervision can be applied prior to tripping and lockout remote breakers, is subjected to individual utility principles and practices. For simplicity, it is recommended to have one BF relay or function per breaker.

BF logic is relatively simple to understand and operate. However, catastrophe can happen if care is not followed properly, particularly for breaker-and-a-half and ring bus with weak fault contribution and insertion of opening resistors. When considering BF scheme, one should be familiar with the BF logic as each manufacturer designs it differently, understand your critical circuit breaker specifications, bus configurations, minimum expected fault level and interactions with other functions such as automatic re-closure and hi-speed sync-check, ...etc.



The important part of any BF scheme is the setting of BF Timer. Before setting the Timer, one must recognize the maximum critical fault clearing time of the system for maintaining its stability which must be greater than the total BF fault clearing time. The total BF clearing time comprises of 2 timing parts, refer to figure 11 Total BF Clearing Time; first is the time at which should normally be cleared by the main protections, measured from the fault initiation to the arc-extinction – a duration of 4 cycles (1 + 3). The second part is the combination of protective relay OC reset time with some margin

plus DTT delay and remote expected breaker clearing time – a duration of 5.5 cycles (1 + 1 + 0.5 + 3). This calls for a total of 9.5 cycles which must be less than the system critical fault clearing time delay. The second part of this 9.5 cycles has included the BF Timer setting. The BF Timer setting must account for the slowest interrupting time of the principle circuit breaker and the longest BF OC reset time plus some margin – a duration of 5 cycles (3 cycles breaker + 1 cycle of protective reset time + 1 cycle of margin).

Breaker failure scheme can be made faster. One is to have a fast circuit breaker interrupting time of two cycles. This is achievable in new design circuit breakers, but unfortunately the majority of HVCB out there are 3 cycles interrupting time. The other option is to reduce the BF OC reset time to less than a cycle with considerable accuracy. A quick solution around the problem is to re-arranged the traditional BF logical blocks, as shown in figure 12 BF Blocks Re-arranged. This BF logical blocks arrangement has worked excellently and well established in most digital BF relays, especially when used with electromechanical relays where resetting mechanism may be unpredictable, thus larger margin would be required for setting BF Timer delay. The theory behind it was only to allow the BF OC detector to run once the Timer 1 has expired which could benefit protection engineers in two ways; one was to permit shorter BF Timer setting and secondly it could be set to more sensitive levels, below load, thus increased dependability.

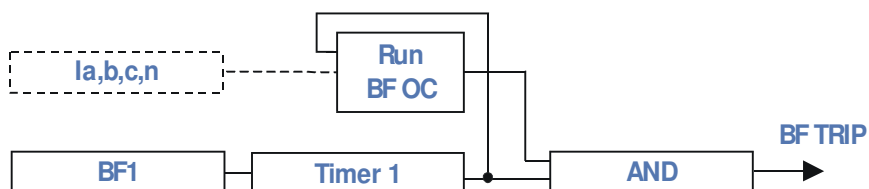


Figure 12: BF Blocks Rearranged

The pickup and dropout times of BF OC detector in digital relays have a direct relationship as to how the filtering and algorithm techniques used. Most digital relays have current magnitude calculated and updated few times within a power cycle. Thus, BF OC detector picks up quite fast once permitted with few milliseconds of security counts applied. In high current fault, it is even faster. This is good for pickup times but bad during resetting period; the higher the fault current, the longer it takes for the OC to reset, especially at low multiples of pickup.

To further complicating the BF OC reset characteristic, severe operating conditions on some power system faults can have an adverse affect on current transformers, as shown in figure 13 DC tail. This dc tail can last up to 2 cycles and may never go across the zero axis line. Ordinary OC algorithm when set too low would take a long time before resetting. Although, this kind of condition is rare, but can happen in high X/R ratio systems for close-in faults with multiple re-closing shots incidentally in the same direction as the magnetizing flux. BF Timer setting must consider this kind of worst case scenario.

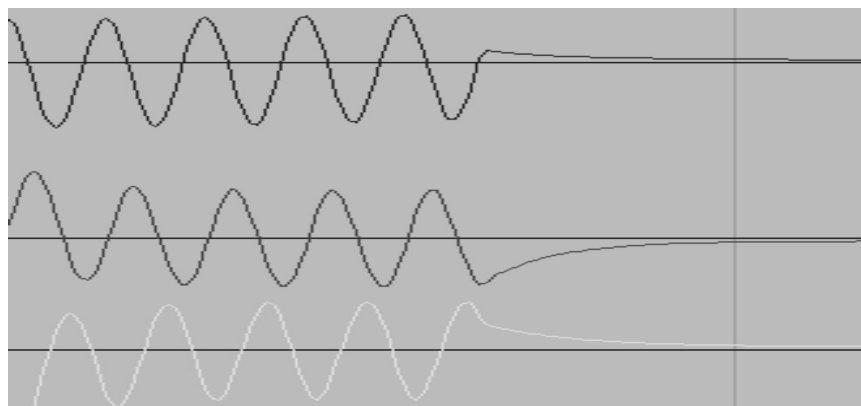


Figure 13: DC tail

Some digital relays have worked out special OC resetting algorithms in order to cope with such severe operating system conditions. Figure 14 Improving BF OC Reset Times, shows significant improvements. Test points were captured at different multiples of current. Significant reduction in reset times up to 90 times of pickup multiples were measured from the BF OC reset.

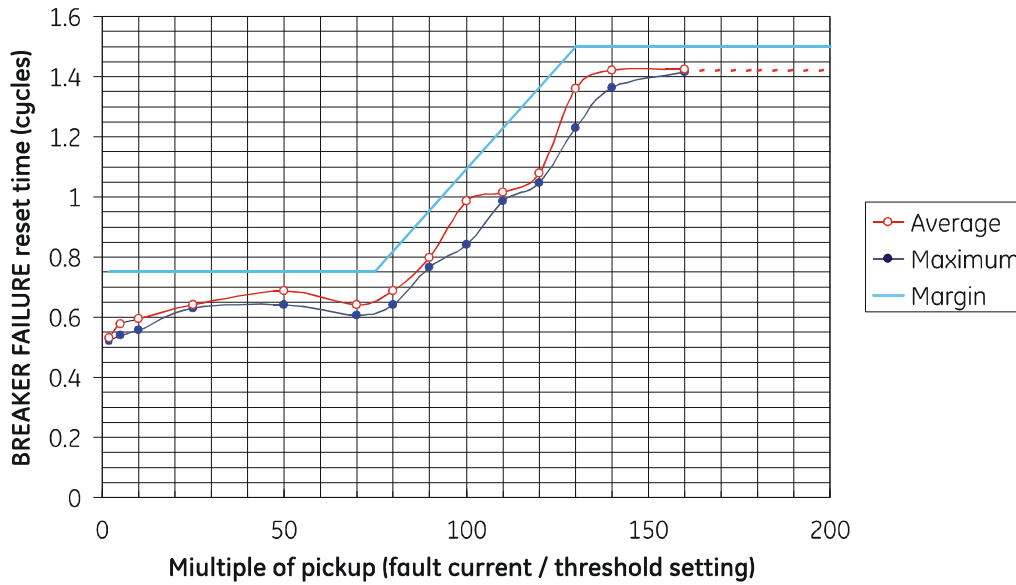


Figure 14: Improving BF OC Reset Times

## 6 Breaker Failure Protection - Enhancements

Obviously, traditional BF logic has weaknesses. Most relay manufacturers have recognized the opportunity and made enhancements to the existing BF logic for better performance. They are described in details in following paragraphs.

- CB2 and CB1 are protected by traditional BF logic as shown in figure15 Breaker-and-a-half; one BF per breaker. Consider a line fault, main protections will trip CB1 and CB2 and associated breakers at remote terminals. If CB2 fails to open and because of weak fault contribution, resulting in very little current flowing in the circuit.

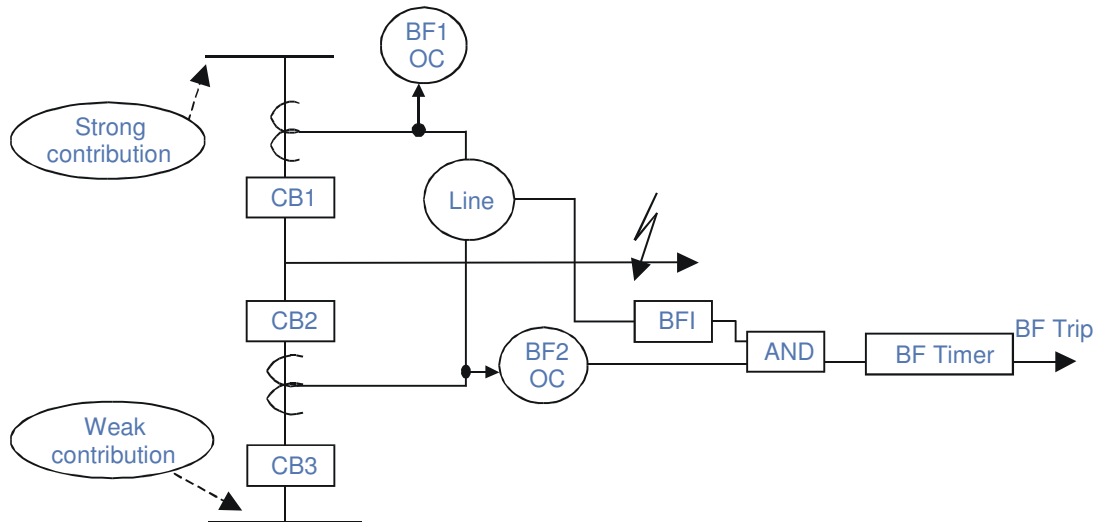


Figure 15: Breaker-and-a-Half using Traditional BF logic delaying trip

This small level of fault current prevents the BF2 OC detector from picking up, delaying the arming of the BF trip. Eventually, CB1 will open and the re-distribution of fault current is high

enough for BF2 OC to pick up and arms the BF Timer. This causes long delay initiating the BF trip, jeopardizing system stability and causing damages to power equipments. When replacing traditional BF logic by slightly modified as shown in figure12 BF Blocks Re-arranged, solves this problem. As seen, the location of BF OC is after the BF Timer. This arrangement effectively arms the BF Timer and does not need to wait for the Timer1 to time out once the current through CB2 is above the BF2 OC threshold. This means that the modified logic will trip back-up breakers instantaneously.

- The 52aa auxiliary contact can be tuned to actuate as soon as the operating mechanism starts to move. This movement or displacement of the mechanism defines the BF Timer2 with some margin. Because this is an early path and current may expect to be above the BF OC threshold, thus it is more likely that the 52aa early contact will stop the timer and reset BF logic. This logic is shown in figure 16 Fast BF Trip using 52aa Contact.

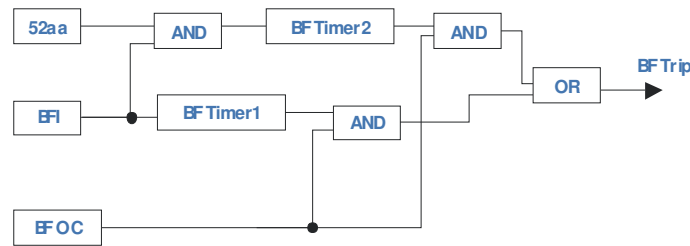


Figure 16: Fast BF Trip using 52aa Contact

- Traditional BF scheme requires that both the BFI and OC to pick up for a full duration of the Timer 1 before asserting the BF Trip. An immediate reset of the BFI signal, for whatever reason, will reset the BF Timer. The BFI input can inadvertently reset from lack of seal-in in the main protection trip output (ie: fault current may drop below the seal-in threshold). In figure 17 BFI Seal-in, the logic must receive an BFI initiation from main protection and an OC seal-in condition for the mechanism to take effect. As long as the OC condition is maintained, the reset of BFI input has no effect on the logic.

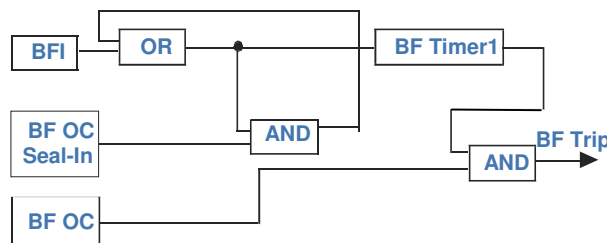


Figure 17: Seal-In

- An incomplete BF Timer is added into the BF logic, figure18 Incomplete BF Timer. This timer provides a window of operation for completing the BF sequence once initiated. Normally, if there is a fault, the main protection will operate the principle breakers and initiating BF. If the fault is interrupted properly, it will reset the main protection trip output. This will release the BFI input and return the BF logic to a ready condition. It is good practice not to set the incomplete BF timer too long as it will defeat its own purpose in a real BFI contact trouble. Consider that the line fault has successfully cleared by main protection. The line AR (auto-reclose) has armed and timing towards re-closing attempt. During this dead time cycle, the BFI contact has found to be defective in “closed” position and causes the incomplete BF sequence timer and the BF Timer to continue timing out. Upon re-closing the line, load current has now present and reported to be above the BF OC detector. The BF OC condition and the expiration of the BF Timer will result in a BF trip. Where auto-reclose is employed, The incomplete timer must not set too long and should coordinate properly with the AR. It is also advantageous to turn on an alarm to notify the operators for further investigation. The incomplete timer is meant to add extra security at the expense of dependability. It will lock out the BF logic when the incomplete BF timer times out.

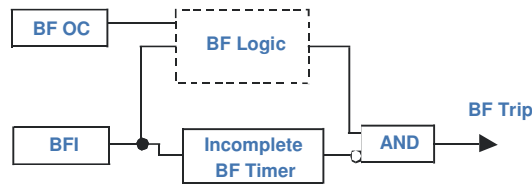


Figure 18: Incomplete BF Timer

- HV circuit breakers need some form of stored energy (spring, hydraulic, pneumatic) or air pressure or gas pressure to aid the arc-extinguishing process and to activate the operating mechanism. A loss in pressure or stored energy, can cause the breaker not function properly should a fault happen.

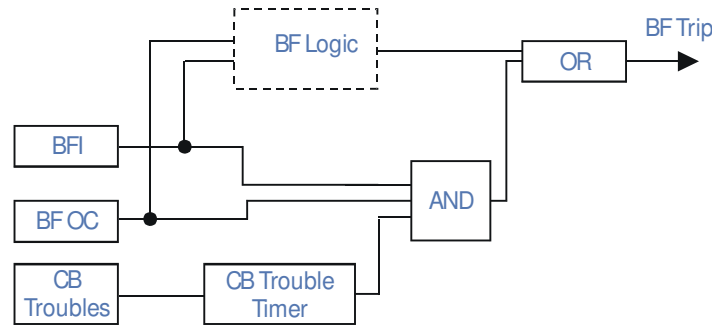


Figure 19: CB Troubles

Thus, it may be advantageous to bring these monitored signals in discrete form, where provided by the CB manufacturer, into the BF logic and let the BF to trip back-up breakers with no additional delay. This logic is meant to work during the fault clearing period such that it must detect both BF OC and BFI conditions, before tripping can occur as depicted in figure19 CB Troubles. Breakers experiencing these symptoms, especially during fault interrupting period, should be tripped and locked out by BF logic or other means to prevent catastrophe.

- It has found that some utility would prefer an additional 52a auxiliary contact as a supervision to the BF logic when its OC detector is set below load current. The logic is shown in figure 20 Additional Supervision. The logic will reset if either the 52a or the Lo-Set OC detector resets.

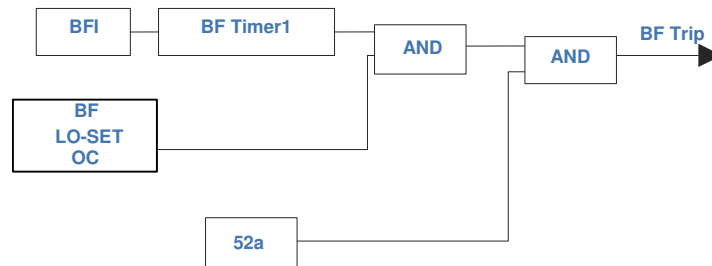


Figure 20: Additional Supervision

- Normally, HVCB is equipped with dual trip coils for purpose of redundancy. Re-tripping attempt may not be found that useful in the case where main1 and main2, each is arranged to trip each trip coil independently and as such for any unclear fault, if not the failure of the circuit breaker itself, re-tripping the same breakers would not be that effective. It is however beneficial during testing, particularly when the BF OC is set below load, necessarily to detect lowest faults. Consider a trip test from one of main protection system, the BF scheme is inadvertently initiated during the test. This will cause the logic to send a “re-trip” command, tripping the principle breakers, refer to figure 21 BF Re-Trip. Once the breakers have opened, the BF logic would also reset. Tripping principle breakers as inadvertently caused by BF re-trip is certainly not desirable, but the consequences could have been worst should the BF Timer expire and current is present.

This will clear all back-up breakers as a result of bad BF initiation. Thus it is a common practice to activate the BF re-trip without additional delay.

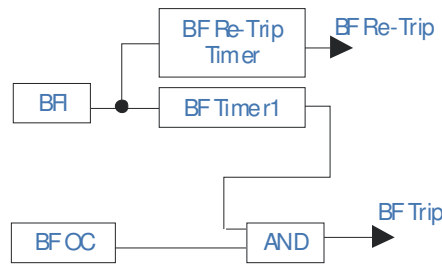


Figure 21: BF Re-Trip

- BF logic can become troublesome when dealing with multiple breakers configuration equipped with the insertion of opening resistors, figure23 Inserting Resistors. Often, for these applications, they require multiple levels of BF OC detectors and timers. As shown in figure 22 Two Timers with Hi-Lo Set OC, the logic allows fast tripping under high current, typically before the insertion of opening resistors should the breaker fail. The BF Lo-Set OC provides a slower path but with greater sensitivity, which normally sets to detect more sensitive faults after the insertion of the opening resistors. This logical arrangement is needed for fast BF clearing under high current faults and more relax for sensitive ones in applications involved circuit breakers with insertion of opening resistors. It should be noted that a small amount of current would still flow in the insertion circuit for period of time before the insertion circuit is completely interrupted.

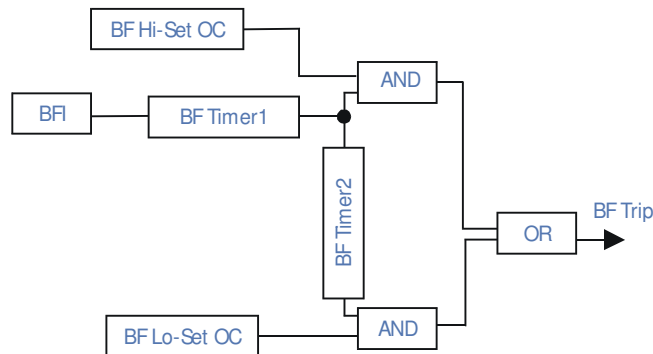


Figure 22: Two Timers with Hi and Lo-Set OC

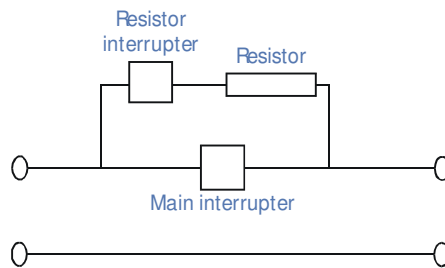


Figure 23: Inserting Resistor

- Faults on transformer or partial transformer in unit differential (transformer and generator) may not draw sufficient current through the failed circuit breaker to be detected by BF OC detector. It may be convenient for BF logic to provide a separate, more sensitive path with the option of using the circuit breaker auxiliary contacts to supplement the BF OC detectors. This type of logic is shown in figure 24 Ring Bus with Sensitive Faults. A 52a contact (or a pair of 52a and 52b) ORed with the BF OC Lo-Set uses to stop the BF trip when either primary current has reset or the breaker has moved to the open position. It is not encouraged to use the breaker auxiliary contact status (52a and 52b) in BF logic, except only when current sensitivity is an issue. This is because

an indication of breaker opening does not mean that the fault has interrupted. Where BF is used for generator breaker back-up; it should be noted that after a successful clearing of short circuit faults within the generator zone of protection (clearing both generator and field breakers), residual current may still present for some time, effectively sealed-in the main protection function. If this is expected, some form of reset mechanism must be provided to both main and BF backup protection in order to stop BF from tripping the bus unnecessarily. Breaker auxiliary contacts can be used to supervise the BF trip logic in such applications.

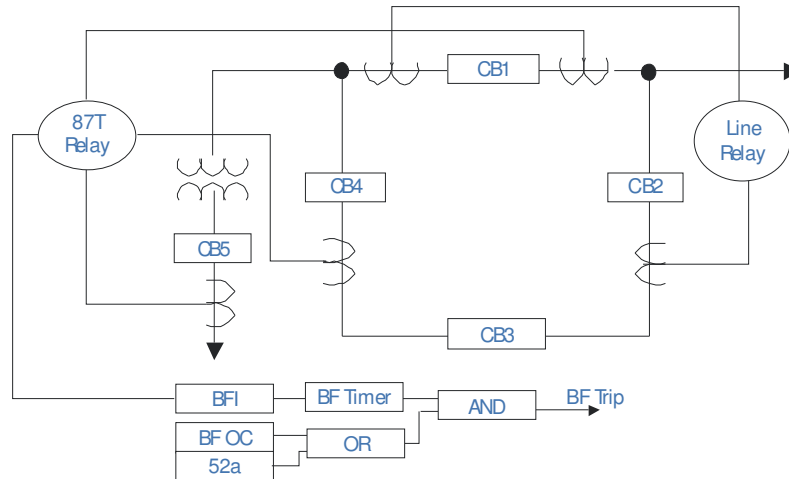


Figure 24: Ring Bus with Sensitive XFRM Faults

Thus far individual parts of figure 25 Enhanced BF Logic, have been broken down and explained in details. This enhanced BF logic can be implemented into digital relays with similar programming capability. The logic provides discrete states for programming purposes and assumes that analog quantities such as Hi and Lo OC pickups have already derived from the relay current inputs and available for use.

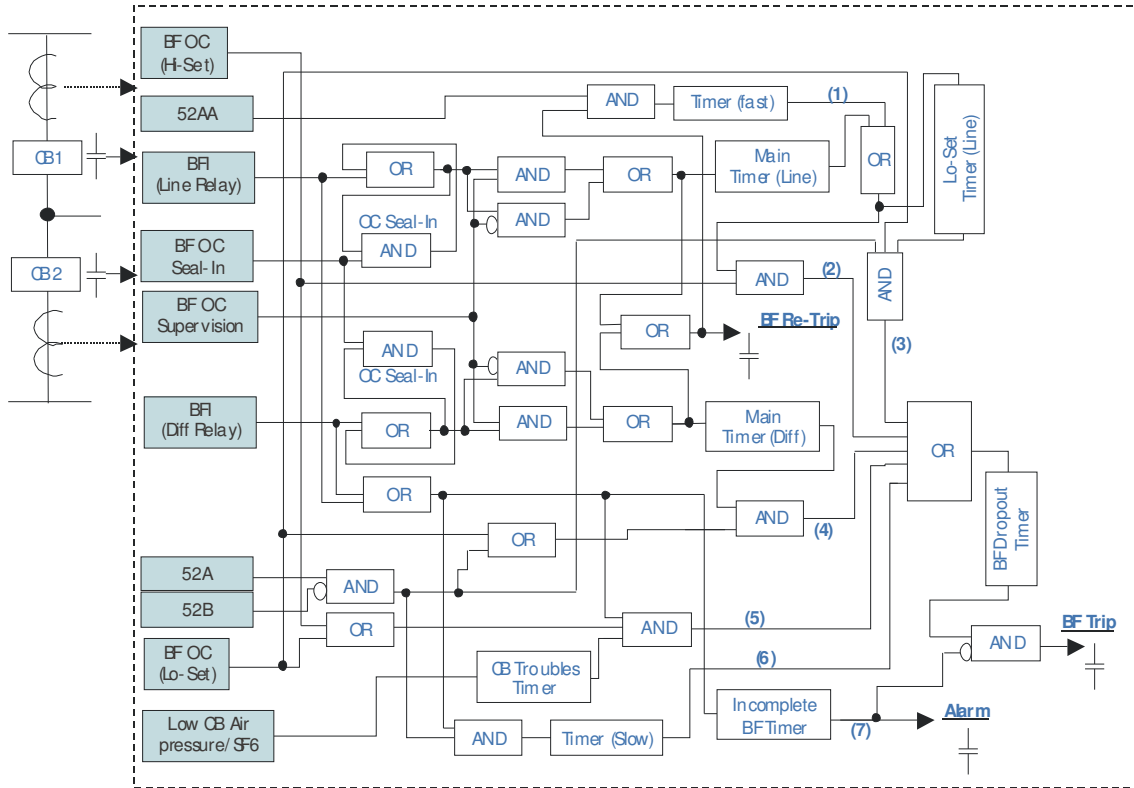


Figure 25: Enhanced BF Logic

- Breaker flashover can significantly damage the interrupter if not detected and cleared within a reasonable time. The indication of breaker flash-over bases on the following measurements: a) Breaker has open previously, b) voltage drop measured from either side of the breaker during the flash-over period, c) voltage difference drop, and d) current flowing through the declared open breaker.

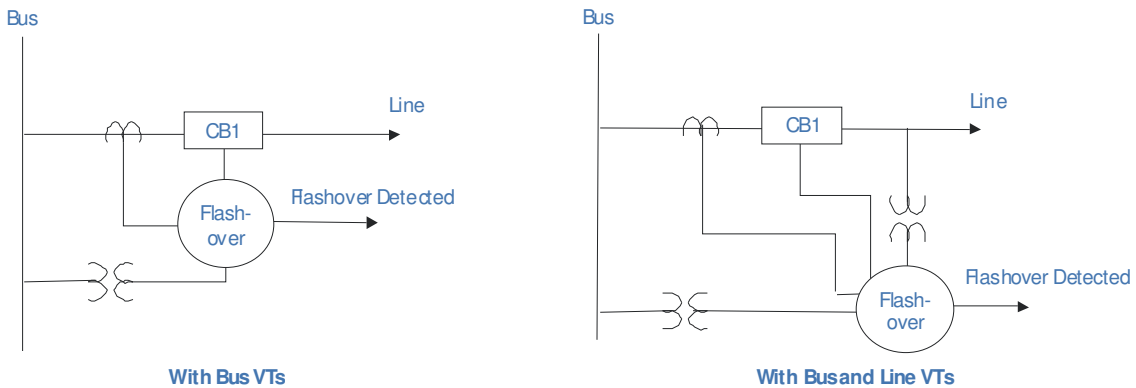


Figure 26: Breaker Flashover

Internal flashover could result from bi-products of heat and interrupting medium surrounding the contacts, reducing the insulating capability between opened contacts.

Flashover happens more often during synchronizing of two previously separated parts of the system, especially with significant line charging current. During this process, the voltage vectors measured at both sides of contacts can be at opposite peaks, resulting in a maximum potential difference drop across the contacts. The space between these contacts and the medium insulation strength have a direct influence to the flash-over condition. Consider figure 26 Breaker



Flashover, with only one bus VTs available (left picture), the logic requires that a contact indication of the open breaker status, bus voltage above the nominal level and no current flowing through the CB1. These indications signify that the circuit breaker has open. If a sudden voltage drop in bus voltage and measurable current through CB1, tells that a flash-over condition is existed. When voltages at both side of circuit breaker (right picture) are available, the extra set of voltage information increases the security of the flash-over detection method. The voltage drop across the breaker as measured from both sides of the breaker is used in addition to the former detection method. The 52a auxiliary contact is recommended for applications where the insertions of closing and opening resistors are used in some circuit breakers. The 52a contact status can be used to differentiate between the voltage drop across the breaker during the period of insertions and breaker already in open position. Moreover, the voltage difference pickup level should be set below the lowest expected voltage difference when insertion resistors are inserted.

## 7 BF Protection applied to single bus/single breaker

For a line fault on circuit 1, figure 27 Single Bus-Single Breaker, both mains will operate simultaneously on CB1 and initiate BF protection. When BF Timer times out and detection of current on BF OC detector, indicates that CB1 has failed, the logic will generate a BF trip to all back-up breakers connected to bus 1, including the tie breaker and sends DTT transfer trip to affected remote breakers. If CB1 opens properly and primary current is interrupted, both BFI and BF OC will revert to ready condition.

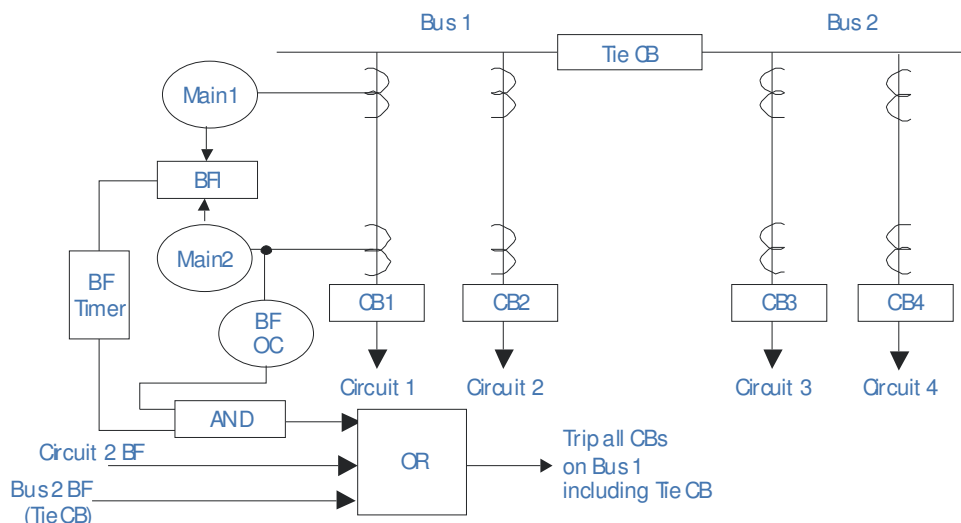
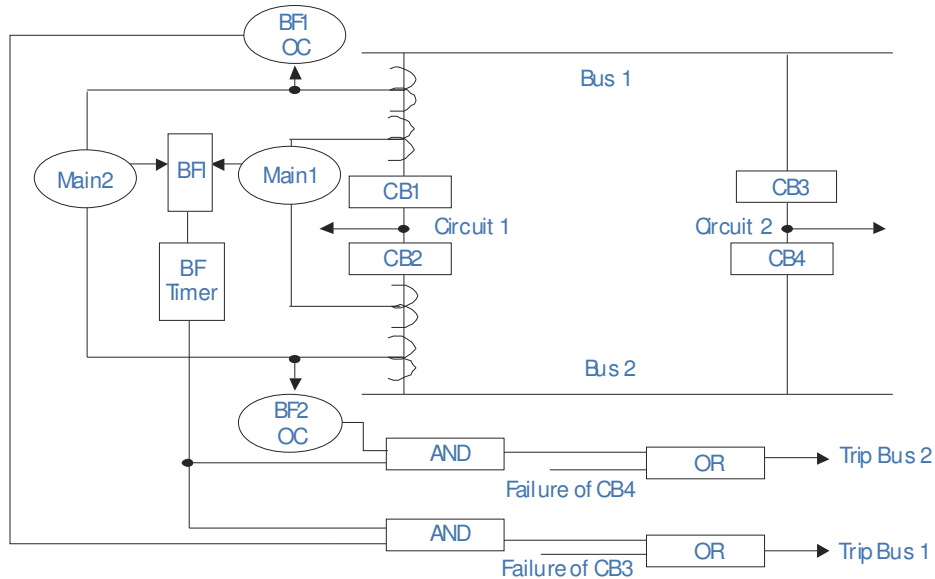


Figure 27: Single Bus-Single Breaker

It should be noted that the BFI must stay energized for as long as the duration of the BF Timer in order to confirm the BF condition. Should initiating contacts from main protections reset, for whatever reasons, BF OC seal-in must be used for correct BF operation.

## 8 BF Protection applied to double bus/double breaker

Consider figure 28 Double Bus-Double Breakers, for simplicity multiple breakers should require multiple BF OC detectors; one on each breaker to identify the failed one. Please note that figure 28 does not show them, but there are two identical BF functions for this configuration. A line fault occurs on circuit 1, line main protections will operate simultaneously to isolate breakers CB1 and CB2 and initiate BF protection.



**Figure 28: Double Bus-Double Breakers**

The receipt of BFI initiation will start the BF Timer. After the expected breaker operating time expires, and the detection of the BF OC condition exists, the logic will assert a BF Trip. In the case of failure of CB2, it will trip bus2 and sends DTT transfer trip to remote terminal(s). Similarly, a failure of CB4 will also clear bus2. It should be noted that if hi-speed auto re-closing is desired on CB1 and CB2 after a line trip, particularly when using very low OC seal-in and BF OC is set below load current. This is a very cautious situation and can cause BF to trip the remaining bus (bus1) unnecessarily. The seal-in effectively seals the BFI unless the current flowing through the associated breaker is less than this seal in level. At the moment CB2 is tripped, an auto-reclose is initiated to bring circuit 1 back to service, can cause a bad BF trip on bus 1 and black out the station. This is because the effectiveness of BF OC seal-in - arming the BFI and the sensitive setting of BF1 OC - below load. It is desirable to have some delay on the hi-speed AR for proper time coordination with the BF logic or at least an indication of both breakers has opened prior to re-closing the line.

## 9 BF Protection applied on ring bus

BF protection applied on ring bus is similar to previous two configurations. One BFI, one Timer and more importantly one BF OC detector per breaker. Other words, there are two BF functions, resided in the same digital relay, although it only shows one BFI block and one BF Timer block on figure 29 Ring Bus.

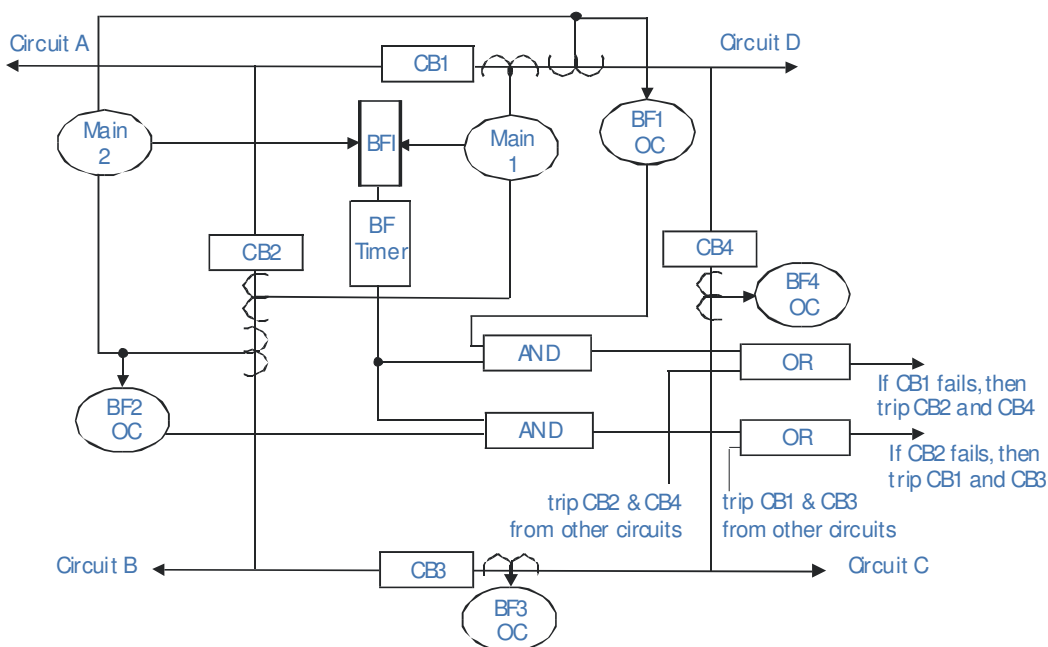
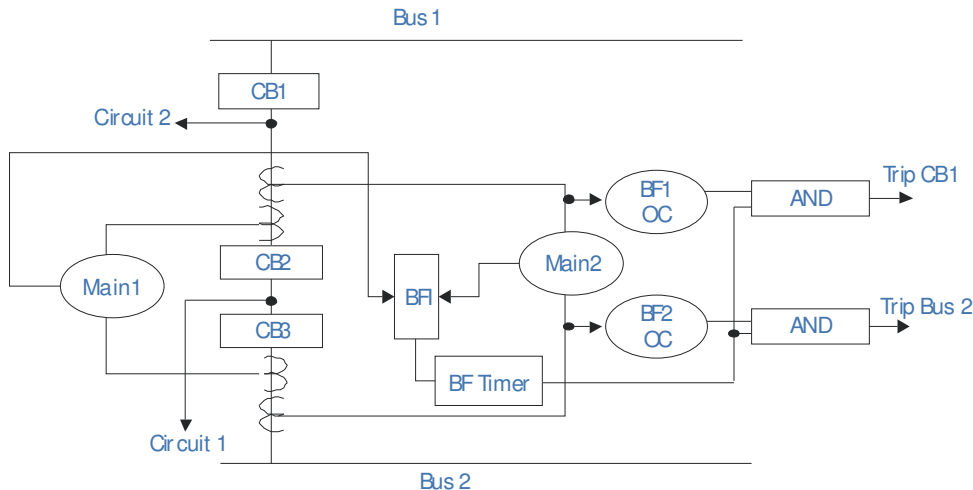


Figure 29: Ring Bus

Figure 29 demonstrates for fault on circuit A only. Other circuits will work out in the same way. A line fault on circuit A, both main protections will trip CB1 and CB2 and initiate BF. After BF timer expires, the logic performs BF OC condition on each circuit breaker (CB1 and CB2). If principle breakers has opened properly, primary current will reset and return the BF logic to normal operation. If per say CB1 has failed, the BF1 OC will pick up and issue BF trip to the next breaker, CB4. Because CB2 has opened successfully, the BF2 OC detector will not arm. There is no danger for sending a trip again to an already tripped circuit breaker, CB2. If the failure is on CB2, the logic will trip CB3 instead of CB4. Furthermore, as shown on figure 29, there two OR gates, each has 2 inputs. The second input to the OR gate can be used for other circuit BF protection which is assigned to trip the same adjacent breaker. For example, if line fault on circuit B and CB3 fails to interrupt, this means that the BF trip on circuit B will trip CB4. In all cases of line faults, it assumes that the main protection will normally clear the line-end breaker. On BF trip, the local BF must also initiate DTT transfer signal to the remote terminal breaker(s) that are included in the back-up breaker circuit.

### 10 BF Protection applied on breaker-and-a-half bus

Again, it is worth to mention that each breaker will have its own BF function. The operation of BF logic applied to breaker-and-a-half configuration is similar to that ring bus. Excepts in the case that if the failed breaker is one of the main one (ie: CB1 or CB3), then the bus which is contributing to the fault must be isolated, as shown in figure 30 Breaker-and-a-Half Bus.



**Figure 30: Breaker-and-a-Half Bus**

For example, a fault occurs on circuit 1, both main protections will operate on CB2 and CB3, and also initiate BF. The initiation of BF starts the BF Timer. If fault current goes away, main protections will reset and stops the BF Timer. If after the expected breaker operating time times out and BF2 OC picks up, this means that CB3 has failed to interrupt the fault. BF logic will trip bus 2. On other hand, If CB2 fails to open, BF1 OC detector will pick up the fault current through CB2 and trips CB1. A DTT will need to transfer to remote terminals for completing the isolation of back-up breakers.

## 11 Conclusions

This paper is intended to serve as a refresher to new/young protection engineers. Circuit breakers do and will fail over time. When designing local BF protection for your HV systems, the followings should be considered:

- One BF relay per breaker.
- BF scheme should be biased to security.
- Know your system critical fault clearing time.
- Work out your total BF fault clearing time, refer to figure 11 Total BF Clearing Time. It must be less than your system critical time defined above.
- Bus, Line, Transformer and Capacitors should initiate BF relay.
- Local BF trip should send DTT to all remote terminals.
- DC supply to BF protection should at least be fused separately from circuit breaker and main protection circuits.
- Avoid mixing the dc grounds. BFI input dc operating voltage should be selected greater than half of the station battery applied.
- Minimize the use of auxiliary relay as it adds extra delay to the BF Timer setting and new point of failure.
- Block re-closing of all tripped breakers.

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