

Primary-Side Transformer Protection

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INTRODUCTION

There are many different protection schemes used today for distribution substation transformers, covering a wide range of expense and complexity—from high-end ring bus and breaker-and-one-half schemes, to low-end flash bus and grounding switch schemes. Given the pressure to increase the continuity of service, more advanced protective devices are called for than a motor-operated disconnect switch to initiate a fault. Today, the best practice is *to individually protect each transformer with a local protective device*. Doing so eliminates the need to take off-line all transformers connected to the transmission line, when only one transformer has experienced a fault . . . unnecessary interruptions to service are avoided.

Secondary-side bus faults are the most common type of event that a primary-side protective device must interrupt. But they may be difficult for some devices due the high-frequency transient recovery voltage (TRV). One might think that a device with a robust fault interrupting rating—such as a 40-kA circuit breaker—would be able to handle a relatively low-magnitude fault on the secondary-side of the transformer. But the secondary-fault interrupting rating of a device is dependant on the device’s *ability to withstand a fast-rise transient voltage—much faster than that seen during high-current fault interrupting*. Therefore, the device must be specifically tested to determine its ability to withstand and interrupt fast TRVs. A device with a 40-kA primary-fault interrupting rating may not necessarily be able to interrupt 4-kA secondary faults with a fast-rise transient voltage.

Standards for testing a device for appropriate secondary-side fault interrupting capabilities—which take into account high-frequency TRVs—are currently being reviewed. The draft standard, PC37.016, “Standard for AC High Voltage Circuit Switchers rated 15kV through 245kV,” [1] provides the testing requirements to verify that a protective device can interrupt a fast TRV. C37.06.1-1997, “Trial Use Guide for High-Voltage Circuit-Breakers Rated on a Symmetrical Current Basis Designated Definite Purpose for Fast

Transient Recovery Voltage Rise Times,” [2] does so as well, although the main C37.06 standard, “AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis,” [3] does not currently incorporate requirements for testing a breaker’s ability to interrupt faults with associated fast-rise TRV, or to require a secondary-side fault interrupting rating.

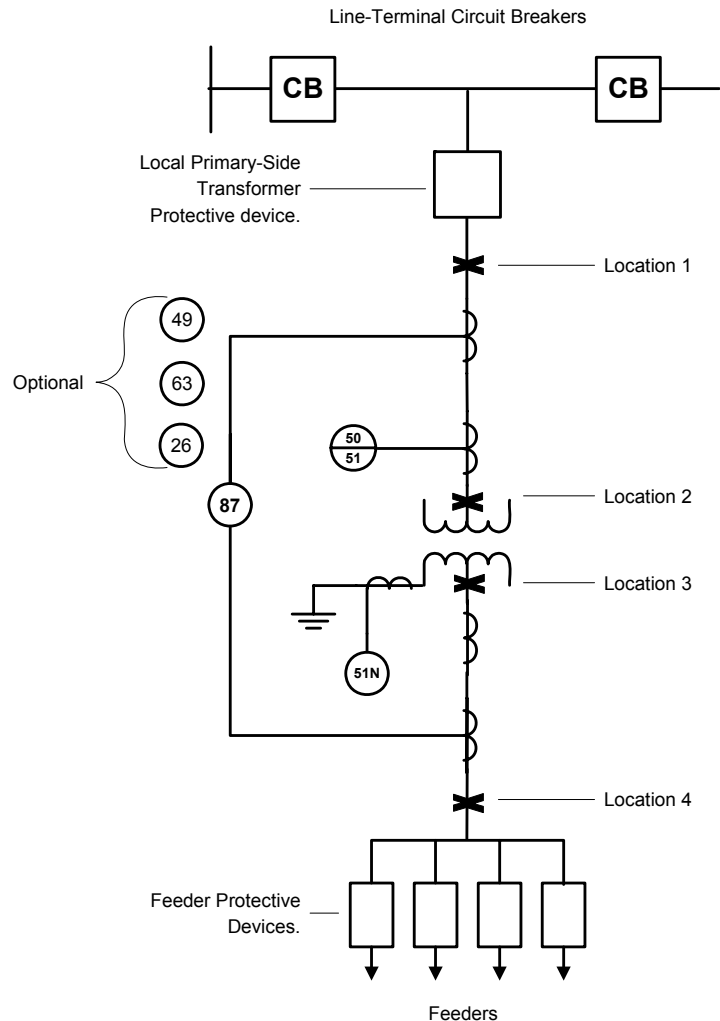
Manufacturers of purpose-built equipment for transformer protection, including the author’s company, have traditionally tested for fast-transient TRVs and provide their equipment with a secondary-side fault interrupting rating. Given the position of the primary-side device and that most fault activity is on the secondary bus, this secondary-side interrupting rating is critical for a primary-side protective device. Before discussing how to select a primary-side protective device, let’s examine the possible locations of faults and the subsequent response of the protective equipment.

LOCATIONS OF FAULTS AFFECTING THE TRANSFORMER

Primary-side protective devices are widely applied at load-tap transformers where the available primary fault current exceeds the device’s primary-fault interrupting rating. Overlapping protection from statistically rare high-current primary faults is afforded by the line-terminal circuit breakers and first-zone phase- and ground-fault line-protective relays. On systems using line-terminal circuit breakers, circuit interruption following a high-current primary fault is typically accomplished by the line breakers in 3 cycles. A local primary-side transformer protective device will respond to faults internal to the transformer and to faults on the secondary bus that is included in its zone of protection. It can also provide back-up protection for the secondary-side protective device(s). A properly applied transformer protective system will overlap some of the protection provided by the line-terminal circuit breakers and supplement the protection afforded by the secondary-side protective device(s).

To understand how a primary-side transformer protective device is applied, let's look at Figure 1. It shows a one-line diagram of the relay protection scheme used for a typical

radially tapped transformer protective scheme—including four locations where faults may occur.



Typical Transformer Protective Scheme Using Relayed Device.

FIGURE 1

Location 1: Faults on Bus Between Transformer Protective Device and Transformer, and Transformer Primary Bushing-to-Ground Faults

The short length of bus and greater line-to-ground clearance make these types of faults rare. Fault current magnitudes in this area can be high because they are only limited by the upstream impedance of the system. This location is typically not part of the relaying for a primary-side protective device due to the location of the primary-side current transformers. It is important to remember that the current transformers for the transformer differential protection are typically located *on the bushings of the transformer*. Therefore, the primary-side protective

device will not receive a trip signal for events on the primary bus, and this device will not get called on to clear full primary-side fault currents on the primary side. For example, primary arrester failures will be cleared by the line terminal breakers, as shown in Figure 1.

Faults in this area cannot usually be detected by the relay schemes used with a local device. If current transformers are available at the primary-side protective device, a relay scheme could be used to cover this small section of the high-side bus but, due to the 3-cycle speed of operation of line-terminal circuit breakers, both devices would respond to the event unless an expensive pilot-wire blocking scheme is implemented. On more complex substation bus

arrangements like ring-bus or breaker-and-one-half schemes, the primary-side protective device usually has current transformers and is used to clear faults in this short section.

Location 2: Transformer Primary Winding Faults

Faults at the transformer primary winding are uncommon in a well-protected and well-maintained transformer. The fault current magnitude can be either high or low depending on the location of the fault within the winding. Typical winding faults are turn-to-turn or multiple-turn and are low magnitude, on the order of load current. Less-likely winding-to-ground faults are limited by the winding impedance to low to moderate magnitude. A winding-to-ground fault near the high-voltage bushing results in high currents limited by the system impedance. These faults are detected by differential, overcurrent, or ground fault relaying, or by sudden pressure, gas analysis, or other overpressure detection methods. Depending on where they occur and the magnitude of the fault current, they will either be cleared by the line breakers or the primary-side protective device.

Location 3: Transformer Secondary Winding Faults

Secondary winding faults are also uncommon in a well-protected and well-maintained transformer. The fault current magnitude can be either low or moderate depending on the location of the fault within the winding. Turn-to-turn and multiple-turn faults are typically low magnitude, limited by the winding impedance. Winding-to-ground faults are of moderate magnitude and always less than the available secondary fault current limited by the transformer impedance. These faults are detected by differential, overcurrent, or ground-fault relaying, or by sudden pressure, gas analysis, or other overpressure detection methods, and are cleared by the primary-side

transformer protective device without disturbing the transmission line.

Location 4: Transformer Secondary Bus Faults and Secondary Bushing-to-Ground Faults

Secondary bus and transformer secondary bushing-to-ground faults represent the majority of faults that a transformer protective device will have to interrupt. With its typically greater length and smaller phase-to-ground distance, it is more likely that wildlife intrusion or nearby equipment problems will cause a fault on the secondary bus. The fault current magnitude is moderate because it is limited by the transformer impedance. Faults in this location are detected by secondary differential or overcurrent protective schemes, and are cleared by the primary-side transformer protective device without disturbing the transmission line.

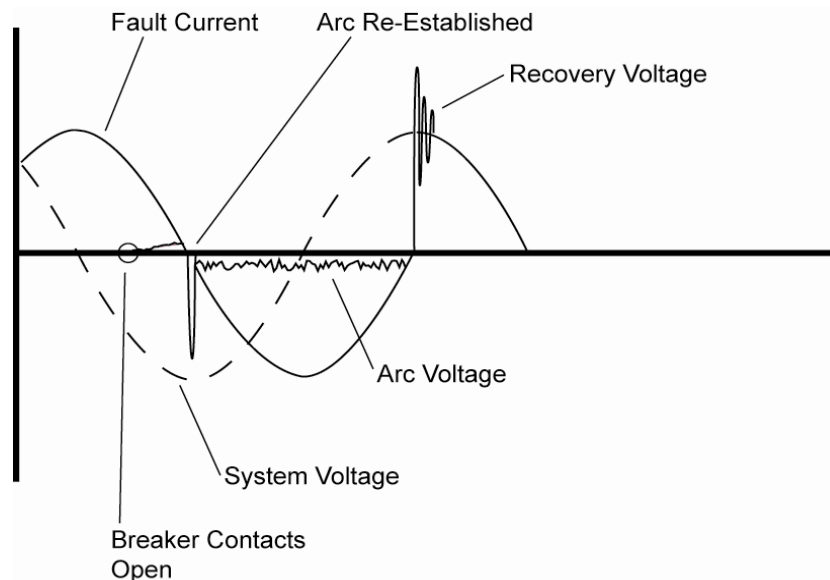
SECONDARY-SIDE FAULT INTERRUPTION

Secondary-side faults, found in Location 4 in Figure 1 (above), are difficult to interrupt. Special attention must be paid to selecting a device that can interrupt these low-current transformer-limited faults. Such faults are limited by the impedance of the transformer, so they have modest magnitudes, but the transient recovery voltage (TRV) frequency seen by the interrupting device after clearing the current is high because of the small bushing and winding capacitance of the transformer, compared to its large inductance.

$$F = \frac{1}{2\pi\sqrt{LC}}$$

To illustrate, a fault in Location 4 would be detected by the transformer's differential relaying, which would signal the primary-side device to open. (See Figure 1.) In a puffer-type SF₆ circuit-switcher or circuit breaker, during the opening

operation, the SF₆ gas is compressed by moving the cylinder supporting the contact system, or by a piston which forces the SF₆ through the interrupting nozzle.



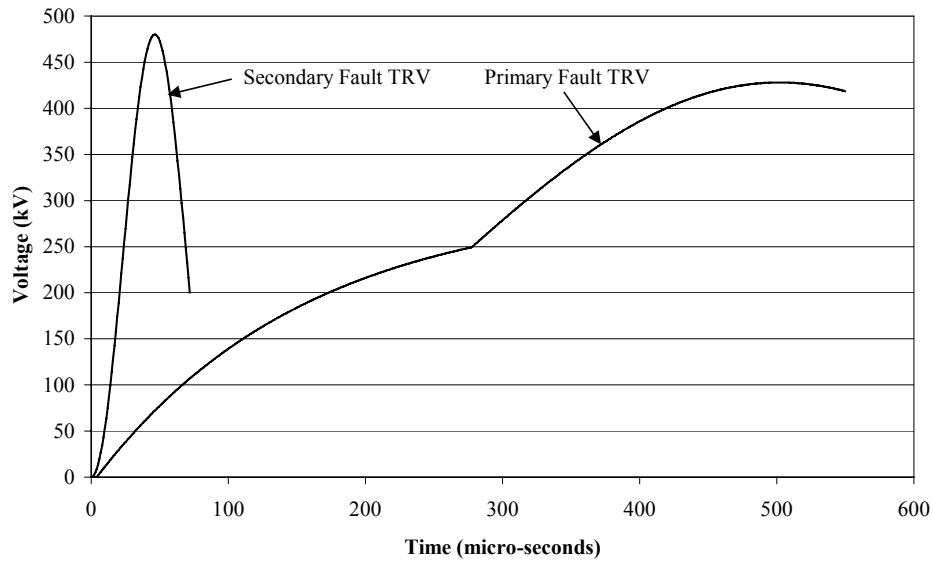
Contact Arc-Interruption and Recovery Voltage

FIGURE 2

This causes a rapid gas flow across the arc, which serves to cool the arc while the arc is lengthened as the contacts move farther apart. By controlling and cooling the arc, its conductivity can be rapidly decreased as the current passes through zero, such that the arc is extinguished and the circuit is interrupted. At that time, the transient recovery voltage across the gap between the contacts is impinged, as a race starts between the cooling processes within the transformer protective device due to increasing dielectric strength and rising recovery voltage across the contacts. If the cooling processes are successful, the interruption is successful and there is no resumption in current. When interrupting a secondary-side fault across a transformer, the reactance-to-resistance ratio (X/R) is high, so fault current will significantly lag the voltage. See Figure 2.

When current is at zero, the voltage is at or near peak. In general, the impedance of the transformer is high compared to the source, so there is a significant voltage (assumed to be .9 per unit. by C37.016) [3] trapped in the stray capacitance of the transformer. As this energy resonates back and forth between the electric field of the stray capacitance and the magnetic field of the transformer inductance, a substantial voltage excursion occurs on the terminals of the transformer protective device, which highly stresses the contact gap due to the high-frequency nature of this excursion—typically on the order of 10 kHz to 15 kHz. If the insulation between the contacts recovers more quickly than the TRV, the interruption is successful. If the TRV creates too excessive a rise in voltage, re-ignition of the arc can occur.

TRV Comparison for a 230 kV Device



TRV Comparison for a 230 kV Device

FIGURE 3

Many primary-side devices are assigned a secondary-fault interrupting rating and tested to ensure that they are capable of interrupting transformer-limited faults. In some cases, multi-purpose devices with high primary-fault interrupting ratings may not be able to interrupt fast TRVs—testing with a fast TRV needs to be specified to ensure the device can handle this duty. See Figure 3.

Secondary fault currents are typically in the range of 2 kA to 6 kA. To determine the fault current seen by the primary-side protective device for a fault on the secondary side, an infinite (zero-impedance) source is assumed. The value can be calculated using the following equation:

$$I = \frac{57.8P}{(\%Z)E}$$

where

- I = Inherent secondary-fault current, amperes
- P = Transformer self-cooled three-phase rating, kVA
- E = Primary-Side System phase-to-phase voltage, kV
- %Z = Percent transformer primary-to-secondary impedance, referred to transformer self-cooled three-phase kVA rating

For example, a 37.5/50/62.5 MVA transformer at 115 kV with 8% impedance will provide an inherent secondary-fault current of 2,356 amperes, calculated as follows:

$$I = \frac{57.8 * 37,500kVA}{8 * 115kV} = 2,356A$$

Therefore, the maximum current on the high side of the transformer resulting from a fault on the secondary side bus will be 2,356 amperes with a high-frequency TRV. The primary-side protective device should be rated to clear this type of secondary fault. [4]

SELECTING TRANSFORMER PRIMARY-SIDE PROTECTIVE DEVICES

Selecting a primary-side device for a new substation can be just as much an economic decision as a technical one. Smaller, less expensive transformers are often protected with power fuses. In the past, these transformers have been protected with remote protection schemes which rely on the line-terminal breakers to protect the transformer, as well as to provide back-up protection for the secondary-side protective device. Larger transformers and transformers serving critical loads are usually protected with devices that use relaying schemes—from simple overcurrent relays to sophisticated combinations of differential, sudden pressure, overcurrent and instantaneous relays that fully coordinate with upstream and downstream devices.

Once a device with the appropriate secondary-side interrupting rating requirements has been identified, the selection process largely becomes a matter of choosing the features and configuration appropriate to the installation. Factors such as available substation real estate, bus layout, seismic requirements, structure height requirements, equipment maintenance cycles, and system ratings are only a few of the factors that must be considered . . . the suitability of the device for a particular substation is usually a matter of utility preference.

In some cases, a device is selected to upgrade a power fuse installation. In such instances, primary-side current transformers, substation batteries, and control power are usually not present in the substation, and the cost of installing this infrastructure is often weighed against the benefits of more-sophisticated relayed transformer protection.

In other cases, a relayed device—like a circuit-switcher or circuit breaker—is selected to upgrade a remote protection scheme. Although widely used in the past, such schemes are slowly being phased out. Remote protection schemes clear secondary-side faults by creating a bolted primary fault, typically with a grounding switch, or use sacrificial switching or a flash bus. The primary fault is then cleared by line-terminal circuit breakers. The entire transmission line is thus interrupted for both primary- and secondary-side faults sensed by transformer relaying, decreasing service

reliability. Faults also take longer to clear, as a result of the sequential operation of two independent systems: the local disconnect switch and the line breakers. Upgrading to a local transformer protective device protects the transformer against the stresses associated with the artificially induced primary-side fault, and will leave the transmission line undisturbed in the event of a secondary-side fault. Much of the relaying and communications used to trigger the protective scheme can be reused with the local protective device.

Selection of a device can also be affected by the bus configuration of the substation. Transformers located on a radial tap off of the transmission line will usually use a single transformer protective device. If there is more than one transformer in the substation, the protective device may be coordinated with a tie switch. When used for transformer protection, circuit breakers or circuit-switchers typically have a minimum of secondary-side overcurrent and sudden pressure relaying. A more critical transformer may have differential relaying and back-up overcurrent relaying, and may also include a neutral overcurrent relay to detect ground faults.

In substations with one or more available sources, the transformer protective device may be coordinated into an automatic switching or “throw-over” scheme. And in urban or dense industrial areas, double-bus or ring-bus arrangements are becoming increasingly more common as the demand for power reliability increases. In these cases, the transformer protective device will have to be rated for both primary and secondary fault interrupting duty as well as for short-line faults—and the associated relay scheme will be quite elaborate.

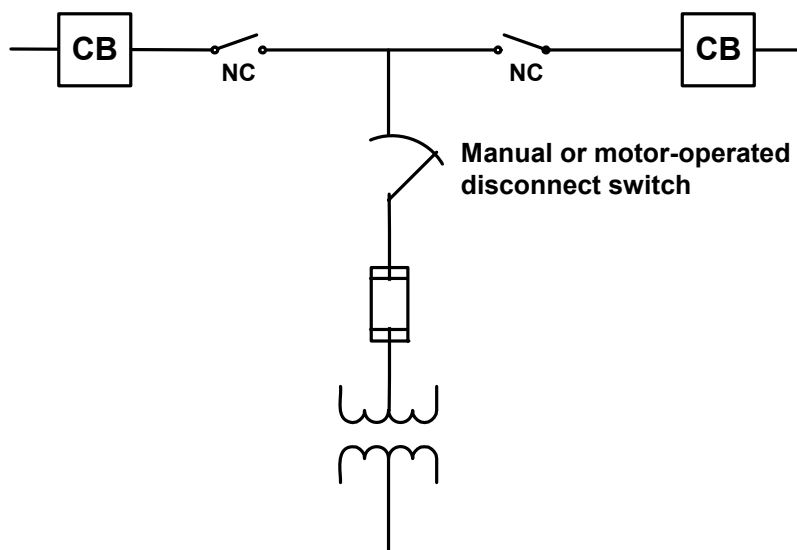
Explaining the different types of protective relay schemes that can be employed with a primary-side device is outside the scope of this discussion. For a detailed description of the types of relays and relay schemes that can be used with a protective device, refer to ANSI C37.91-1985, “IEEE Guide for Protective Relay Applications to Power Transformers.” [5]

The following is a brief overview of the different local primary-side transformer protective devices available today.

Power Fuses

Power fuses, shown in Figure 4 in a typical transformer protective application, provide protection that is both reliable and economical. They are inexpensive—both in

initial purchased cost and installed cost. When properly applied, their characteristics remain unchanged over their operational life. Power fuses are generally applied on transformers rated 10 MVA and smaller.



Power Fuses in Typical Transformer Protective Application

FIGURE 4

The operating procedure for power fuses is straightforward. Typically, after a fuse has operated, the load-side circuit breaker, switch, or recloser is opened. (If no load-side device is in place, the main-secondary circuit breaker or recloser is opened.) Then the line-side series disconnect is opened. Transformer inspection and maintenance can then be performed, and the fuses replaced. To restore service, the line-side series disconnect is closed to pick up transformer magnetizing current. Then the load-side circuit breaker, switch, or recloser is closed.

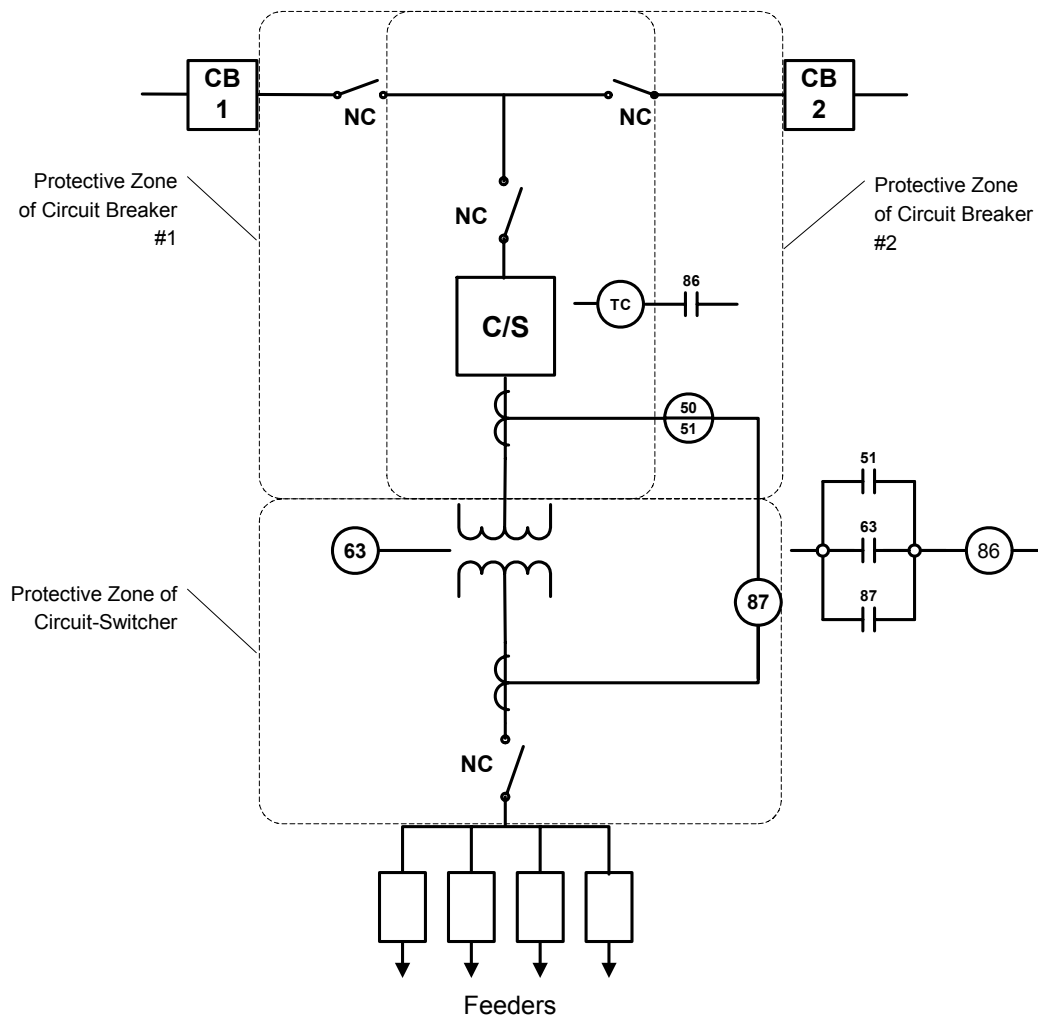
As mentioned previously, the advantage to using power fuses is their relative low-cost compared to a relayed transformer protective device. Disadvantages include the difficulty in coordinating fuses for secondary-side faults and single-phasing of downstream devices in the event of a single-phase fault. Also, there is no way to implement more advanced relay schemes using differential, neutral overcurrent, or sudden pressure relays. [5]

Circuit-Switcher

The author's company developed the first circuit-switcher in 1960 for use in capacitor switching and transformer protection. Early on, it was recognized that the main duty for a circuit-switcher applied for transformer protection

would be in clearing secondary faults, so an extensive study of the frequency response of transformers was launched to develop a test method for ensuring that circuit-switchers could clear such faults. The work done at that time is the basis for the present proposed standard. Circuit-switchers use stored-energy operating mechanisms to drive the interrupters open, and have trip-free operating capability. In the event the circuit-switcher is closed into a fault, it will open immediately to interrupt the fault. Many circuit-switcher models are equipped with integral disconnect blades, which provide visual assurance of the device's state and provide working clearance for transformer maintenance or repair.

Shown in Figure 5 is a typical primary-side transformer protection application. Circuit-switchers use the same type of protective relaying as circuit breakers and both devices provide a similar level of protection. The operating procedure for a circuit-switcher is similar to that of a circuit breaker. After the device has tripped, the circuit-switcher disconnect or separate line-side disconnect is opened—either manually or, in some cases, automatically—to isolate the transformer. Then the load-side series disconnect is opened. Transformer inspection and maintenance can now be performed.



Circuit-Switcher in Typical Transformer Protective Application

FIGURE 5

To restore service, the relays are reset, the load-side series disconnect is closed, and the circuit-switcher is then closed. Circuit-switchers have trip-free operation. So if either the circuit-switcher or the line-side disconnect is closed into a fault, the circuit-switcher will trip to clear the fault.

Unlike circuit breakers, circuit-switchers typically have a short-time current rating higher than their interrupting rating. The reason for this goes back to the rarity of primary faults and the difficulty in coordinating a transformer protective device with line-terminal circuit breakers, which react to and clear high current faults within 3 cycles. For high current faults, a circuit-switcher typically does not interrupt—either because it is located outside the local zone of protection, or because the line-terminal circuit breakers operate faster than the typical 5- to 8-cycle operating time of the circuit-switcher. It is common practice to apply a primary-side protective device that can carry *but cannot interrupt* the full available high-side fault current on the primary side of the transformer.

Circuit-switchers are available in models from 34.5 kV through 345 kV, with primary-fault interrupting ratings from 8 kA up to 40 kA, secondary-side fault interrupting ratings from 2600 to 4200 amperes, and interrupting times between 3 and 8 cycles.

Faults on the secondary side are low magnitude, so a 3, 6 or 8-cycle operating time will not have much effect on the amount of stress put on the transformer windings. Internal transformer faults are usually detected early in their development by differential or sudden-pressure relays, before much fault current is flowing. And obviously, an internal transformer faults will typically necessitate the removal of the transformer from service and untanking of the transformer for inspection and repair. Generally speaking, a complete rewinding is warranted regardless of whether the fault persisted for 3, 5, 6, or 8 cycles. For these reasons, the fault clearing time of a circuit-switcher isn't as important in selecting a transformer protective device as the ability to successfully interrupt secondary-side faults.

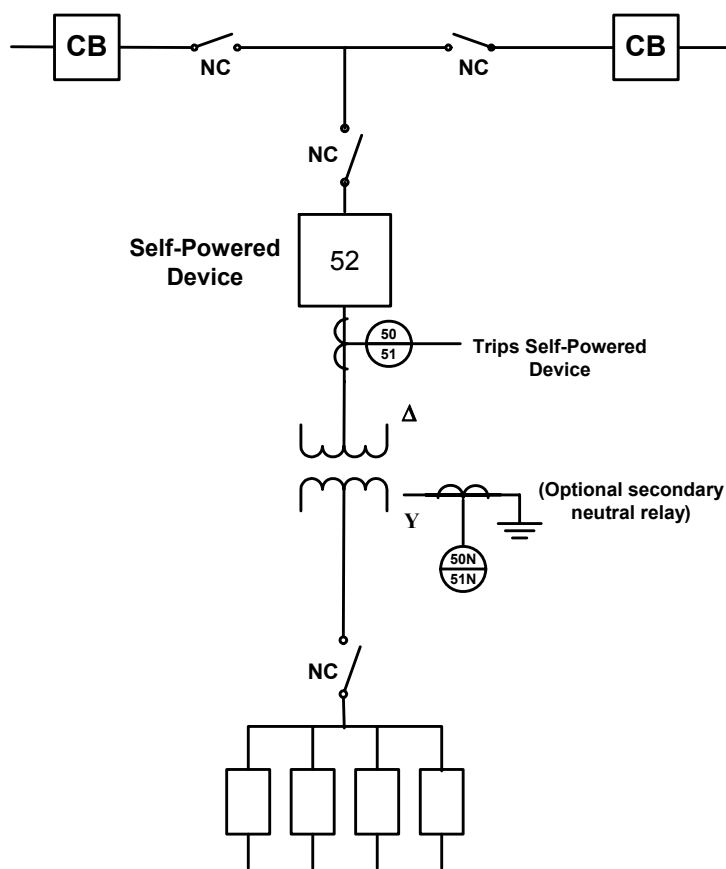
The advantages of circuit-switchers include their ability to provide economical transformer protection, and their ability to be used with a whole range of protective relay schemes. Many circuit-switchers include integral disconnect blades, which reduce the overall installation time in getting the installation on-line. Disadvantages are that they typically do not have high-speed reclosing or short-line fault capability. And, due to their live-tank design, the addition of current transformers is quite expensive. This excludes circuit-switchers from use in more complex bus schemes where the transformer protective device also acts as a line protective device.

Transformer Protective Device

The author's company has developed a low-cost power fuse and circuit-switcher replacement which utilizes a modular

design. The transformer protective device features puffer-type interrupters similar to that used in circuit-switchers. These interrupters provide a 31.5-kA fault interrupting rating and a 3-cycle interrupting time. Transformer protective devices have been tested for their ability to interrupt fast TRVs and are assigned a secondary-fault interrupting rating similar to circuit-switchers. Each pole-unit is self-contained with its own operating mechanism; the pole-units are filled with SF₆ and sealed.

Two versions are available: one which requires an external power source and user-furnished relaying, and one with a self-contained overcurrent protection relay system. The self-powered version is pictured below. (Figure 6.)



Transformer Protector with Overcurrent Protection in Typical Transformer Protective Application

FIGURE 6

The operating procedure for the self-powered version is similar to that of power fuses. After the device has tripped, the load-side circuit breaker, switch, or recloser is opened—either manually or, in some cases, automatically—to isolate the transformer. (If no load-side device is in place, the main-

secondary circuit breaker or recloser is opened.) Then the line-side series disconnect is opened. Transformer inspection and maintenance can now be performed. To restore service, the pole-units are manually closed and charged for the next opening with a charging tool provided with the device. Each

phase is charged separately. Thus, steps for visually verifying the charged status of each phase must be incorporated into the substation operating procedure. After the relay targets have been reset, the line-side series disconnect is closed, picking up transformer magnetizing inrush current. Then the load-side circuit breaker, switch, or recloser is closed. The self-powered version is trip-free; in the rare event that the line-side disconnect is closed into a fault, it will trip to clear the fault.

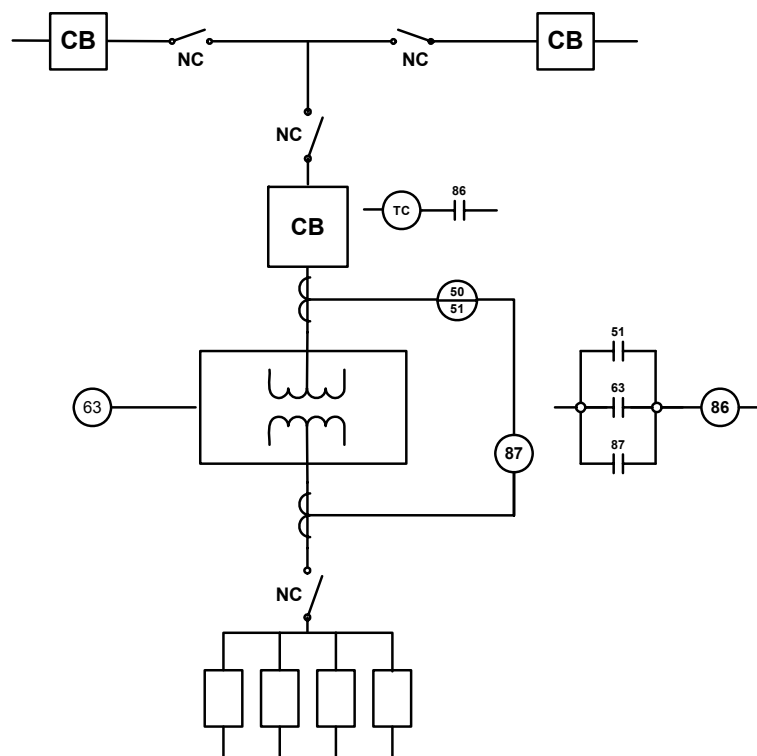
The transformer protective device was specifically designed for application on distribution substation transformers. At full load current, it has a continuous current rating of 420 amperes. At 69 kV, it can protect up through a 30/40/50-MVA transformer and it has a 4200-ampere secondary-side fault interrupting rating. At 115 kV, it can protect up through a 37.5/50/62.5-MVA transformer. At 138 kV, it can protect up through a 50/66.5/83-MVA transformer and it has a 2600-ampere secondary-side fault interrupting rating. At the upper extremes of the application range, there are some limitations with respect to the minimum impedance of the transformer, so as to stay within the secondary fault rating of 2600 amperes. [4] [6]

The advantages of transformer protective devices include their ability to provide very economical transformer

protection, and their ability to be used with a whole range of protective relay schemes. The compact design and light weight of these devices make them suitable for application where there is little room for a larger protective device. The disadvantage is that some users' operating practices do not allow energizing of a transformer using a disconnect switch—although many users have been doing it for years for fuse applications.

Circuit Breaker

Circuit breakers are also used for transformer protection, as shown in Figure 7. Like circuit-switchers, circuit breakers are relay-activated. Breakers offer higher interrupting ratings than power fuses and circuit-switchers, are SCADA-compatible, and work with the same protective relay schemes as circuit-switchers. Breakers are generally used in complex bus schemes, such as ring-bus or breaker-and-one-half schemes. In those situations, the breaker acts as both the transformer protective device and the protective device for the incoming lines—thus the need for high-speed reclosing, short-line fault interrupting capability and, in many cases, high primary-fault current capability. In the United States, dead-tank breakers are typically used since current transformers can be economically applied.



Circuit Breaker in Typical Transformer Protective Application

FIGURE 7

The latest designs of circuit breakers use puffer-type SF₆-filled interrupters, as were previously discussed in the section on secondary-side fault interruption. Circuit breakers generally have a stored-energy mechanism that allows the breaker contacts to open and close one or more times after control power has been lost. These mechanisms can be pneumatic or hydraulic, and use compressed air or another compressed gas, or a motor-compressed spring. [3]

For transformer protection, the high-speed reclosing capability of circuit breakers is often undesirable and, in most cases, should be blocked. When the primary-side transformer protection trips in a response to a fault internal to the transformer, it's generally for a good reason. A visit to the substation is usually necessary to determine if the transformer has been damaged. The transformer insulation is tested, and a gas or oil analysis may be performed to check for arc byproducts. In some cases, a turns-ratio test is performed. Since almost no transformer protective scheme uses high-speed reclosing, the feature is unnecessary.

Circuit breakers are "general purpose" switching devices designed for application in a variety of areas on a utility system. Although circuit breakers often have an extremely robust interrupting rating, they are not always tested for their ability to interrupt the fast TRVs associated with secondary-side faults. This rating needs to be specified when purchasing a circuit breaker for transformer protection.

CONCLUSION

Providing a local primary-side protective device for each distribution substation transformer affords the best protection against secondary-side faults, and eliminates unnecessary disturbances on the transmission line. When selecting a primary-side protective device, careful examination must be made of its secondary-side fault interrupting capability. Other factors must be taken into consideration, including the cost of the transformer, the criticality of the load, and the available resources.

REFERENCES

- [1] IEEE PC37.016; DRAFT, "Standard for AC High-Voltage Circuit-Switchers rated 15kV through 245kV."
- [2] ANSI/IEEE Standard C37.06.1-1997; "Trial Use Guide for High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis Designated "Definite Purpose for Fast Transient Recovery Voltage Rise Times."
- [3] ANSI/IEEE C37.06 – 2000; "AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis – Preferred Ratings and Required Capabilities."
- [4] IEC Standard 60056, "High Voltage Alternating Current Circuit Breakers," Edition 4.0: 1987.
- [5] ANSI/IEEE C37.91-1985; "IEEE Guide for Protective Relay Applications to Power Transformers."
- [6] ANSI/IEEE C57.109-1993; "Guide for Transformer Through-Fault Current Duration."