Circuit Breaker Ratings – A Primer for Protection Engineers

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***Abstract*—This paper explains the asymmetrical short-circuit interrupting current rating for high-voltage circuit breakers. The paper teaches how the decaying dc component in the asymmetrical fault current affects the breaker, and it explains how the X/R ratio and the relay operating time affect the asymmetrical current breaker rating. The paper briefly introduces, and illustrates with field cases, several ultra-high-speed protection principles that can operate in just a few milliseconds. The paper then explains how to derate a breaker for the relay operating time that is shorter than the standard reference value of 0.5 cycle. The paper calculates the "rating loss" due to fast tripping and suggests that applying customary margins when selecting breakers may be sufficient to mitigate the effect of ultra-high-speed relays without the need to replace breakers.**

I. Introduction

The four major components of any protection system are instrument transformers, protective relays, circuit breakers (CBs), and control power circuits. Current and voltage instrument transformers supply input signals to protective relays. Protective relays provide a wide range of protection functions, including but not limited to short-circuit protection. When tripped by protective relays, breakers interrupt the fault current to isolate the affected zone from the rest of the power system.

In high-voltage applications, the differential and directional comparison schemes, as well as the underreaching distance and overcurrent elements, provide instantaneous protection against short circuits. With security as the paramount performance factor, the faster and more dependable the protection system, the better. With all other factors equal, a faster relay is always preferred over a slower one.

Instrument transformers create well-recognized challenges for protective relays. Designed for the fundamental frequency component, instrument transformers may introduce transient errors. Capacitively coupled voltage transformers (CCVTs) generate slowly-decaying components in their output voltages that challenge both speed and security of distance protection elements, especially in weak systems. Current transformers (CTs) may saturate due to high currents or long-lasting decaying direct current component (dc) offset in the primary current. Protective relay designers and practitioners have a good grasp of these instrument transformer transients, limitations, and failure modes. For example, we know how to derate a CT to account for the actual CT burden, dc offset (X/R ratio), residual flux, or low-frequency operation.

In contrast to their focus on instrument transformers, relay practitioners pay less attention to the other component of the protection system – the circuit breaker. This paper aims at closing this gap and introducing protection practitioners to the basics of breaker rating.

Manufacturers specify the fault current interrupting capacity of their breakers for a set of reference conditions including, among other factors, voltage, frequency, decaying dc offset in the fault current, relay operating time, temperature, and altitude. This paper teaches the basics of how breakers are specified and explains rules for derating breakers for operating conditions that differ from the standard reference values. Special attention is given to the decaying dc offset in the short-circuit current and the relay operating time.

As per current standards, the fault current interrupting rating of a breaker accounts for the asymmetrical fault current interruption; i.e., it accounts for the decaying dc offset in the fault current. The decaying dc component is time varying. It subsides and makes the current interruption an easier task with the passing of time. The key standards for CBs, ANSI/IEEE C37.04 [1] and the IEC counterpart IEC 62271-100 [2], use the X/R ratio of 17 (60 Hz system) and the 0.5-cycle relay operating time to establish a reference condition for the decaying dc component. With these assumptions, the standards ask breaker manufacturers to specify the nameplate interrupting rating for an asymmetrical current. As a result, breaker applications are simplified because the users can directly apply the nameplate rating without extra calculations if their relays are not faster than 0.5 cycle and their system X/R ratio is at or below 17.

How does one derate a breaker for relay operating times that are faster than 0.5 cycle or a system X/R ratio higher than 17? Breaker practitioners routinely derate breakers for systems with higher X/R ratios. Historically, however, the 0.5-cycle relay operating time was rarely questioned, and today, users normally do not derate breakers to account for specific relay operating times.

Today, new types of relays have emerged that operate faster than 0.5 cycle [3]. Application of these relays calls for evaluating breaker ratings. This paper is a primer for protection engineers, and it teaches how the breaker rating depends on the X/R ratio and the relay operating time (Sections II and III). It briefly discusses relay operating times and the new principles that allow reducing operating times to just a few milliseconds (Section IV). The paper then introduces, explains, and illustrates the breaker derating formula for ultra-fast tripping

times (Section V). The paper analyzes the impact of the relay operating time (faster and slower than the reference value of 0.5 cycle) for a few breaker interrupting times. The paper shows that the changes in the breaker ratings due to ultra-fast relay operation are within typical margins applied by breaker practitioners.

II. Circuit Breaker Specification Convention

Requirements and specifications for power circuit breakers and circuit switchers have been established in various standards over the years. These standards are principally the ANSI/IEEE standards, C37.04, C37.06, and C37.09, and the IEC counterpart, IEC 62271-100. The standard for circuit switchers is ANSI/IEEE C37.016.

We briefly summarize several key specifications and explain their purpose and application [1] [2] [4].

1) Normal Operating Conditions

These specifications refer to environmental conditions, primarily the ambient temperature and the altitude. The ANSI standards specify a temperature range between –30°C (–22°F) and +40°C (104°F) and an altitude below 1,000 m (3,300 ft).

2) Rated Power Frequency

System frequency has a significant impact on the interrupting capability of a breaker because it dictates the rate of change of the current near the current zero crossing. The breakers are specified at either 60 Hz or 50 Hz, and they need to be derated for operation at different frequencies.

3) Maximum Operating Voltage

This rating specifies the maximum line-to-line rms voltage for a breaker. The ANSI and IEC standards differ slightly on the nominal values they recommend. For example, the IEC may list 525 kV while ANSI may list 550 kV. These differences result from the rated network voltage practices in various parts of the world.

4) Rated Voltage Range K-Factor

This rating originated with older breaker technologies (such as oil and air magnetic breakers) in which the interrupting capability is inversely proportional to the operating voltage. The K-factor is the ratio of the rated maximum voltage to the lowest operating voltage for which the inverse relationship between the operating voltage and the interrupting current holds true. The K-factor is a limit for derating the interrupting current for a varying operating voltage. Older breaker technologies had significantly higher current interrupting capability at lower voltage; hence, breakers were essentially constant MVA-rated fault clearing devices. At the time they were most common, the standards used the concept of the rated (symmetrical) short-circuit current and allowed derating based on the operating voltage. Today's breaker technology (SF_6) does not have this same characteristic: the increase in the current interruption capability at lower operating voltages is usually rather small and as such is frequently ignored. The K-factor, therefore, does not apply to modern breakers.

5) Rated Dielectric Strength

This group of ratings is specified by a series of tests, each relating to typical power system overvoltage transients, that a breaker needs to pass. These tests include conditions such as low-frequency overvoltage (nominal frequency, wet and dry conditions), lightning impulse (basic impulse level), chopped wave, bias test, and switching impulse.

6) Rated Transient Recovery Voltage

Transient Recovery Voltage (TRV) relates to the ability of the breaker insulating medium to recover its insulating properties after current interruption. A breaker needs to recover its insulation for the specified TRV waveform across its terminals. The standards consider this waveform a function of the system alone and neglect any interaction between the system and the breaker. TRV is a complex requirement that depends on the system conditions such as fault type. The standards specify several TRV waveforms (conditions) assuming different fault and system scenarios such as terminal faults or short line faults.

7) Rated Continuous Current

This value relates to the breaker's thermal design and the allowable temperature rise from the losses dissipated across the primary contact and connection resistances. This rating needs to be considered in relation to the ambient temperature.

8) Rated Short-Circuit Current

This value refers to the maximum rms symmetrical short-circuit current (the current without any decaying dc component) that can be safely interrupted by the breaker. Historically, this specification was used to convey the breaker's total interrupting capacity, neglecting the impact of the decaying dc component and leaving to the user the derating for asymmetrical short-circuit current. The symmetrical short-circuit current rating was often considered with the MVA rating, allowing derating for operation at lower voltages (constant MVA rating means higher current capability at lower operating voltage). New breaker technologies (SF_6) do not allow higher current ratings at lower operating voltages. In addition, today the standards account for decaying dc offset in the short-circuit current, specifying the asymmetrical current rating.

9) Asymmetrical Currents

These specifications relate to asymmetry in the short-circuit current, including the following: a decaying dc offset in the short-circuit current during faults with a breaker closed (we describe asymmetrical short-circuit current rating in Section III); close and latch current (peak making current or peak asymmetrical closing current), which refers to a condition of closing onto a fault; and short time current, which relates to the thermal current carry capabilities for external faults, i.e., without opening the breaker.

10) Duty Cycles

These specifications relate to multiple breaker operations in various sequences, such as Open – Close-Open (O-CO) and further duties of O-CO-CO. Breaker duty cycles, especially with the older breaker technologies, have significant residual effects after interruption such that they reduce the fault clearing

capability with repetitive breaking and closing in a rapid succession. Significant derating needs to take place for extended duty cycles, such as when using multiple-shot autoreclosing.

11) Capacitive Switching

An additional set of requirements relates to switching capacitive loads, such as capacitor banks, back-to-back capacitor banks, and long cables or lines.

III. Current Interrupting Rating

A. Current Interrupting Rating Convention

As we briefly explained in Section II, the following factors impact the breaker short-circuit interrupting capability:

- Historically, the symmetrical current rating was specified following the "constant MVA" rating principle of the oil and magnetic air breakers. The symmetrical short-circuit rating could be derated for the actual operating voltage (Current Rating = MVA / Operating Voltage) within the limits of the K-factor. Also, the users had to derate the symmetrical rating for any specific asymmetrical current condition.
- Asymmetrical current rating is now used as a standard rating, assuming the reference X/R ratio of 17 and the relay operating time of 0.5 cycle.
- Peak closing current rating and duty cycles also impact the overall applicability of a given breaker in any given location in the grid.

To understand the impact of asymmetrical currents on breaker operation, we need to understand the timing diagram for the short-circuit current interruption. Referring to Fig. 1, we recognize the following time instances and time intervals:

- The *fault initiation time* starts the diagram. The fault current begins to rise at that moment, and if it contains a decaying dc offset, the current waveform will have the maximum possible dc offset at that time. The worst-case scenario is the fully offset waveform with the dc offset initially matching the peak value of the symmetrical ac component.
- The *relay operating time* (or a *release delay*) is the time interval it takes for a relay protecting the apparatus to operate and issue a trip command to the breaker. This trip command is in the form of the trip coil current, and therefore, it includes trip-rated relay outputs or interposing relays as required. Historically, 1-cycle relay operation was considered typical. The standards assume 0.5-cycle relay operating times for specifying the asymmetrical breaker rating. In Section VI, we discuss the relay operating time in more detail.
- The breaker *opening time* (or mechanical time) is the time it takes for the breaker to open the contacts enough to start drawing an arc across the primary contacts. This time is measured from the start of the trip current in the breaker trip coil to the moment the primary contacts start to arc.
- The *contact parting time* is an interval between the fault inception and the primary contacts starting to arc. According to the breaker standards, the short-circuit current at this specific point in time (including both the ac and dc components) is the primary factor controlling the asymmetrical current rating of the breaker.
- The *arcing time* is a time of arcing; i.e., a time between parting of the primary contacts until the following current zero crossing (0.5 – 0.75 cycles) at which time the current is normally interrupted.
- The *clearing time* is measured from the fault inception until the last pole of the breaker interrupts the current.
- The *breaker interrupting time* is a fraction of the clearing time between the breaker actuation and the end of the clearing process. This time is the "breaker operating time."

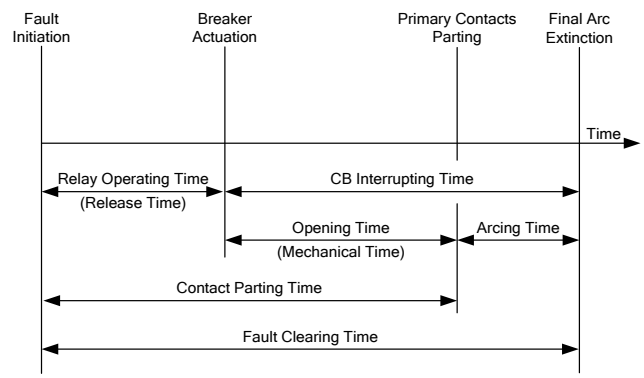

Fig. 1. Fault clearing sequence.

The current level when the primary contacts part and start drawing an arc is the key factor for breaker interrupting ratings. This current includes the ac short-circuit current component and a decaying dc component value.

B. Impact of DC Offset on Interrupting Rating

When the breaker contacts move apart, an electric arc (composed of highly ionized plasma) bridges the space between contacts. The breaker must remove the arc plasma energy before a successful interruption can occur at the following current zero crossing. For a given ac short-circuit current component, the level of decaying dc component increases the fault current peak values. This in turn results in an increase in the degree of plasma ionization in the arc just prior to the current zero where the interruption can take place (see Fig. 2). The level of the peak current for the last peak before the interruption is the single most significant variable controlling the breaker's ability to clear faults. A fault with a dc component is more difficult to clear than a symmetrical current. Such a fault requires derating the breaker symmetrical capability so that the peak current is maintained within the breaker design limits to assure a successful interruption.

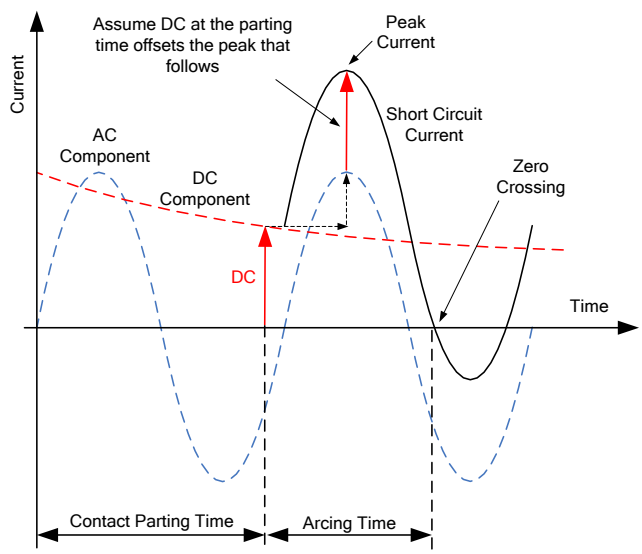

Fig. 2. DC component increases the peak current prior to zero crossing.

For example, if the dc component is 80 percent of the ac value, the peak value of the fault current with both the ac and dc components is 1.8 times the ac peak value, or the ac rms value is $1.80 \cdot \sqrt{2} = 2.55$. The rms value of the current with both ac and dc components in this example is the geometrical sum of the ac rms value and the dc rms value. The dc rms value is the same as the dc value itself, i.e., $0.8 \cdot \sqrt{2}$ times the ac rms value. Therefore:

$$I_{RMS} = \sqrt[2]{1^2 + \left(0.8 \cdot \sqrt{2}\right)^2} = 1.51 \text{ pu} \tag{1}$$

Both the ANSI [1] and IEC [2] standards recommend calculating the rms value of the combined ac and dc components and using it for derating breakers for the decaying dc offset. The standards define an "asymmetry factor" S as follows:

$$S = \sqrt[2]{1 + 2\left(\frac{DC\%}{100}\right)^2} \tag{2}$$

Consider three sample data points for illustration.

With no dc component present (DC% = 0), the asymmetry factor is 1. This means, the symmetrical and asymmetrical ratings are the same, as one would expect if the fault current does not contain any dc component.

With the dc component being half of the ac component (DC% = 50%), the asymmetry factor is 1.22. This means the symmetrical rating needs to be 22 percent higher than the ac component in the asymmetrical current to maintain breaker margins for interrupting this asymmetrical current. In other words, the breaker can claim 100%/1.22 = 82% of its symmetrical rating as its asymmetrical rating.

With a dc component of 0.8 (DC% = 80%), the asymmetry factor is 1.51. This means, the symmetrical rating needs to be 51 percent higher than the ac component in the asymmetrical current. In other words, the breaker can claim 100%/1.51 = 66% of its symmetrical rating as its asymmetrical rating.

Fig. 3 plots the asymmetry factor S and the percentage reciprocal of S. The percentage reciprocal tells us the fraction of the symmetrical rating that may be claimed as the asymmetrical rating for a given dc component content.

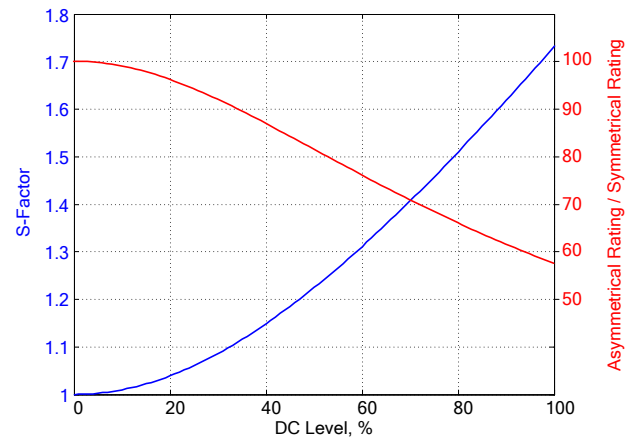

Fig. 3. Asymmetry factor S (blue) and asymmetrical rating to symmetrical rating ratio (red) as functions of the dc level in the fault current.

The standards assume the worst-case scenario, in which the initial dc offset is the highest possible value, i.e., 100 percent of the ac value (fully offset case). Further, the standards assume a single exponentially decaying dc offset. Therefore, the initial dc value decays with time (t) as follows:

$$DC\%(t) = 100\% \cdot e^{-\frac{t}{T_{DC}}} \tag{3}$$

Where T_{DC} is the decaying time constant.

For any given power system frequency (f), the time constant depends on the system X/R ratio:

$$T_{DC} = \frac{L}{R} = \frac{1}{2\pi f} \cdot \frac{X}{R} = \frac{1 \text{ cycle}}{2\pi} \cdot \frac{X}{R} \tag{4}$$

The standards [1] and [2] specify an X/R of 17 as the reference value for the asymmetrical rating, which results in a decaying time constant of 2.71 cycles. In other words, the standards assume a condition when the dc component completely decays in about 8.5 cycles (three time constants).

When using (3) we must consider time (t) to be the contact parting time. This time is the sum of the relay operating time and the breaker opening (mechanical) time (see Fig. 1). The latter is a breaker parameter and therefore can be left out of the standards. The former is an independent factor. Standards [1] and [2] specify the relay operating time of 0.5 cycle as the reference condition for the asymmetrical rating.

Fig. 4 plots the S-factor as a function of the contact parting time assuming the standard T_{DC} time constant for the X/R is 17. The standards allow breaker manufacturers to neglect the asymmetry and test with symmetrical currents for S < 1.1.

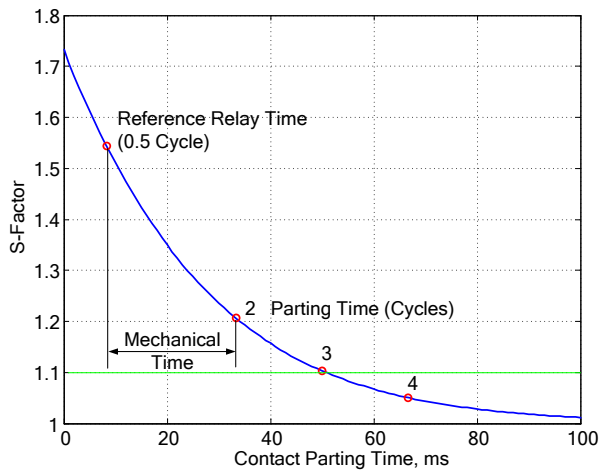

Fig. 4. Asymmetry factor S as a function of contact parting time for an X/R of 17.

C. Current Interrupting Rating Margins

Circuit breakers are expensive pieces of equipment. If a breaker is pushed beyond its design limits, it could not only fail and need to be replaced but its failure to clear a fault would trigger breaker failure protection and tripping of potentially large numbers of breakers. This would result in de-energizing many loads and generators.

Power systems slowly evolve as equipment is added or replaced. This changes the short-circuit levels and X/R ratios. In addition, a typical short-circuit calculation would have accuracy of 5 percent if not worse (due to the limited accuracy of models and parameters). As a result, breaker practitioners apply hefty margins in breaker ratings. It is not uncommon to have a 20-percent margin in the asymmetrical current rating. This margin allows for system growth and may be reduced over time.

IV. Relay Operating Time

Typically, protective relays provide short-circuit protection based on the fundamental frequency components in voltages and currents associated with the protected apparatus. The electromechanical relay technology brought in unavoidable "filtering through mechanical inertia" to protective relaying. Solid-state (static) relays allowed relay designers a choice of how much filtering to apply, but these relays did not gain a wide-spread adoption because of the success of the relay technology that followed – the microprocessor-based relay.

Early microprocessor-based relay designers were forced to use phasors to afford lower sampling rates and to provide a wide range of functions with the limited processing power available at the time. This phasor-based approach continues today. As a result, it is a common expectation that high-performance protective relays operate in about one power system cycle [5]. "High-speed" elements available in some relays use less filtering for faster operation, and typically specify operating times between 0.5 cycle and 1 cycle. But these elements are less dependable, and they operate as "accelerators" for the phasor-based elements. Many static relays were specified with 0.5-cycle operating times, but their security was sometimes problematic.

Interposing and lockout relays also play a role in the discussion on the relay operating time. Historically, protective relays in high-voltage applications did not trip breakers directly, but they actuated interposing or lockout relays. Some older breakers required trip currents as high as 20 A and these higher currents called for more robust contacts than were commonly available in protective relays. These interposing relays typically operated in 2 to 6 ms or in about 0.25 cycle. Therefore, even if the protective relay operated in a few milliseconds, the breaker actuation time was not shorter than about 0.5 cycle.

Because of the specified relay operating times, actual in-service operating time records, and the "slowing-down" role of the interposing relays, the industry settled on an assumption that breakers will not be tripped faster than in about 0.5 cycle for a short circuit. Hence, the reference point of 0.5 cycle for the relay operating time in the breaker standards [1] [2].

Today, we need to revisit this assumption.

A. Elimination of Interposing and Lockout Relays

Many microprocessor-based relays incorporate trip-rated outputs. These outputs have the current make and carry ratings, as well as the voltage ratings, that allow them to be directly connected to breaker trip coils, assuming the 52a breaker contacts take care of interrupting the current. Today's breakers require trip currents at the level of about 5 A, making the application of tripping directly from the protective relay outputs even more practical. Some of these outputs allow mechanical position retention even upon the loss of power to the relay, thus permitting elimination of stand-alone lockout relays. Some applications provide lockout via an interlocking logic rather than mechanical position retention. Yet other applications rely on the operator's procedures and timers to prevent reclosing rather than relying on lockout relays. As a result, an increasing number of new installations (and retrofits) eliminate the interposing and mechanical lockout relays to improve the overall reliability of the protection system and to lower the material and labor costs [6].

Some of these trip-rated outputs use semiconductors and can close in a short fraction of a millisecond. This creates another benefit – faster tripping.

Because of this trend of tripping directly from the trip-rated outputs of microprocessor-based relays, the relay operating times are shortened by several milliseconds, or by about 0.25 cycle. The assumption that a breaker will never be actuated faster than in 0.5 cycle becomes questionable.

B. High-Performance Relays Using Naturally Secure Protection Principles

A few protection principles are inherently secure and therefore can be very fast. These principles, when implemented on a low-latency relay platform with semiconductor-based trip-rated outputs, can issue a trip signal to a breaker in about 0.25 cycle for high-current internal faults when breaker

interrupting ratings are challenged. These principles are as follows:

1) Bus Differential Protection

High-impedance bus differential schemes are inherently very secure. When combined with a low-latency overcurrent or overvoltage element specifically designed to work with signals expected in these schemes, the high-impedance bus differential scheme may operate well below 0.5 cycle.

Modern low-impedance differential schemes incorporate fast and dependable external fault detectors [7] that provide excellent security for CT saturation during external faults. In applications to bus protection, these differential schemes can therefore operate very fast, especially when implemented on low-latency relay hardware with semiconductor-based trip-rated outputs.

2) High-Set Unrestrained Transformer Differential Protection

Unlike bus differential schemes, transformer differential schemes need to rule out magnetizing inrush as a cause of the differential signal before they can operate. Harmonic-based inrush detection is typically used. This method of dealing with inrush requires about 1 cycle to release the transformer differential relay to operate on an internal fault. Today, waveshape-based inrush detection methods [8] are adopted, and they need only about 0.5 cycle to rule out inrush during heavy internal faults.

High-set unrestrained transformer differential elements differentiate between faults and inrush based on the differential current level alone. Recently, improved versions of the unrestrained transformer differential logic have been introduced, such as the method described in [8]. This logic compares the unipolar (inrush) vs. bipolar (many internal faults) nature of the differential current and allows tripping in about 0.5 cycle. Some relays allow instantaneous (sample-based with minimum or no filtering) high-set unrestrained differential operation or even operation based on the rate of change of the differential current. As a result, transformer differential relay operating times shorter than 0.5 cycle are becoming possible. This is especially true for high-current in-zone faults that are not limited by the impedance of the transformer.

3) Stub-Bus and Switch-Onto-Fault Protection

Stub-bus protection detects faults on a piece of buswork between one or two closed breakers and the opened line disconnect switch in a temporary bus configuration. A typical case is two breakers that are closed to maintain the ring-bus or the breaker-and-a-half configuration while the line or other connected apparatus is out of service. In dual-breaker applications stub-bus protection is best accomplished by enabling a low-set differential overcurrent element when the disconnect switch is open. With security inherent in the differential principle, differential-based stub-bus protection is very fast. If a simple overcurrent element operating on the summed currents is used (unrestrained differential), a short time delay may be needed to account for CT saturation during external faults.

Switch-onto-fault (SOTF) protection detects faults on a line being energized, both genuine faults as well as switching errors such as closing the breaker on safety grounds. It is accomplished by enabling a low-set overcurrent element for a short time after the breaker closes, if the breaker was open for some time and the line-side voltage was not present confirming the line was not already energized from the opposite terminal.

Both these protection schemes may work with extremely high multiples of pickup (the operating current may be many times higher than the pickup setting). The SOTF pickup setting may be especially low for short lines that do not draw large charging currents when energized.

Therefore, the stub-bus and SOTF protection schemes may operate very fast. We are aware of field cases of SOTF schemes that have operated as fast as 2 ms.

C. New Line Protection Principles

Recently, new line protection principles [5] found their way into products [3]. These principles are based on incremental quantities (time-domain (TD) elements) and traveling waves (TWs). This subsection briefly reviews these new protection elements: directional elements (TD32 and TW32), a distance element (TD21), and a differential scheme (TW87); it also illustrates their operating times with field cases.

1) TD32 Directional Element

To realize the TD32 directional element, a time-domain relay calculates an incremental replica current (Δi_Z) as a voltage drop resulting from the incremental current (Δi) at the relay location through an RL circuit with unity impedance (1 Ω) [5]. As Fig. 5 shows, the incremental replica current is directly proportional to the incremental voltage (Δv) at the relay location. For forward faults, the incremental replica current and the incremental voltage are of opposite polarities (Fig. 5a). They are of matching polarities for reverse faults (Fig. 5b).

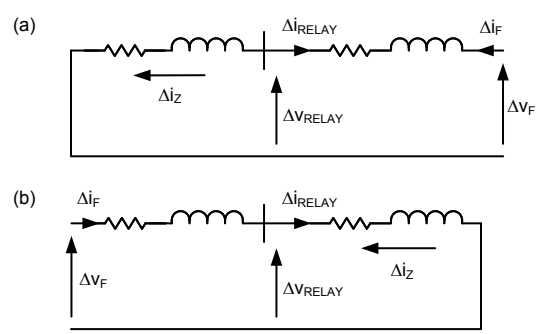

Fig. 5. TD32 directional element operating principle for forward (a) and reverse (b) faults [9].

When implementing the TD32 element, the relay [3] uses six measurement loops (three ground loops and three phase loops) to cover all fault types; calculates and integrates an operating torque; and applies adaptive thresholds for enhanced sensitivity, speed, and security [5].

The time-domain relay [3] uses the TD32 element in the POTT scheme, to supervise the TD21 element, and in some applications, to supervise the TW87 scheme.

Fig. 6 shows a fault record for a single-line-to-ground fault on a 500 kV, 69.9 mi series-compensated line in a 60 Hz system. The fault was 16.984 mi from the local terminal. The local and remote TD32 elements asserted in 1.5 ms and 2.2 ms, respectively. This application uses a direct fiber channel for the POTT scheme with a communications latency as short as about 0.6 ms including processing the transmitted and received packets by the two relays. Because of the extremely fast assertion of the directional elements, the low-latency POTT channel, and the relatively low POTT overcurrent trip supervision settings, the POTT scheme operated in 2.8 ms and 2.2 ms, at the local and remote terminals respectively. This relay [3] has semiconductor-based trip-rated outputs that closed is less than 10 µs. If connected directly to the breakers, this relay would have actuated the breakers as early as 2.2 ms into the fault (this installation is in a monitoring mode and does not trip breakers at this time).

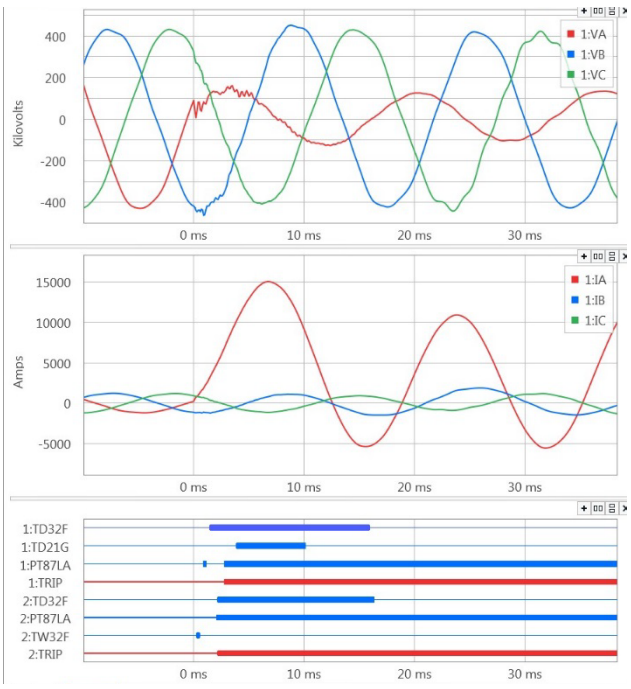

Fig. 6. Field case example showing the operation of the ultra-high-speed incremental-quantity and TW elements and the POTT scheme. The local and remote terminals are labeled 1 and 2, respectively.

2) *TD21 Distance Element*

To realize the TD21 distance element, a time-domain relay calculates as its operating signal, the change in the instantaneous voltage at the intended reach point using the incremental replica current, incremental voltage, and line RL parameters. The element operating condition is derived from the observation that the prefault voltage is the highest possible value of the voltage change at the fault point. With reference to Fig. 7, if the calculated voltage change at the reach point is higher than the prefault voltage at the reach point, the fault must be closer than the set reach, m_1. If this is true and the TD32 element asserts forward, the TD21 element operates [5].

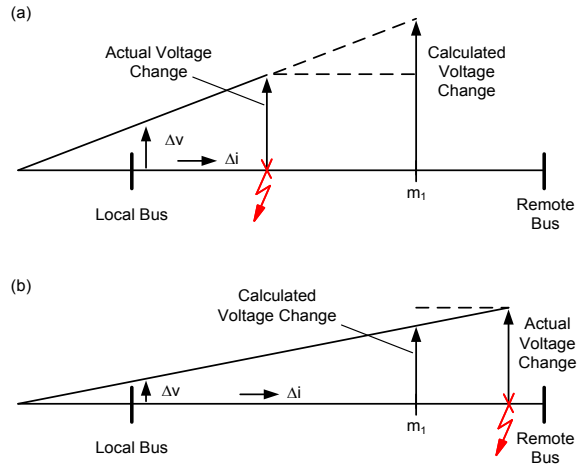

Fig. 7. TD21 element operating principle for in-zone (a) and out-of-zone (b) faults [9].

When implementing the TD21 element, the time-domain relay [3] uses six measurement loops to cover all fault types, and it applies an instantaneous prefault voltage at the reach point as a restraining signal for sensitivity and speed.

To appreciate the TD21 operating time, refer to Fig. 6. The fault is within the local terminal TD21 reach. The TD21 element operated in 3.9 ms. Therefore, even if the POTT channel were not available for this case, the relay would still have operated in 3.9 ms using the communications-independent TD21 element.

Fig. 8 shows another field case of TD21 operation for a single-line-to-ground fault on a 110 kV, 56.31 km line in a 50 Hz system. The fault was within the TD21 reach. The TD21 element operated in 1.8 ms for this fault. The operating time is partially credited to the magnetic voltage transformers, which responded quickly to the voltage change.

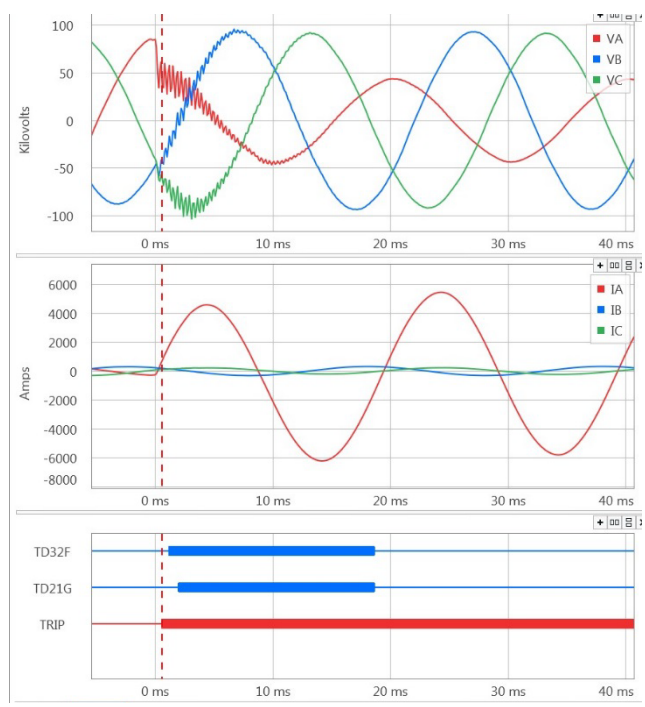

Fig. 8. Field case example for the TD21 element.

3) TW32 Directional Element

The TW32 directional element compares the relative polarity of the current TWs and the voltage TWs. For a forward event, the two TWs are of opposite polarities; for a reverse event, they are of matching polarities [5]. To realize the TW32 element, the time-domain relay [3] filters the TW signals, integrates a torque calculated from the current and voltage TWs, and checks the integrated value a few tens of microseconds into the fault (see Fig. 9). As a result, the relay responds to the TW activity during the few tens of microseconds following the first TW. Once asserted, the TW32 element latches for a short period of time to act as an accelerator for the dependable TD32 element for permissive keying in the POTT scheme.

When applied with CCVTs, the TW32 element benefits from the parasitic capacitances across the CCVT tuning reactor and step-down transformer, which otherwise block the high-frequency TW signals. These capacitances create a path for these signal components, allowing some voltage TW signals to appear at the secondary CCVT terminals. The element only needs accurate polarity and timing of the first voltage TW, and therefore, the element is suitable for CCVTs despite their poor reproduction of voltage TWs, especially for the second and subsequent TWs. The relay in [3] uses the TW32 element to accelerate the permissive key signal in the POTT scheme.

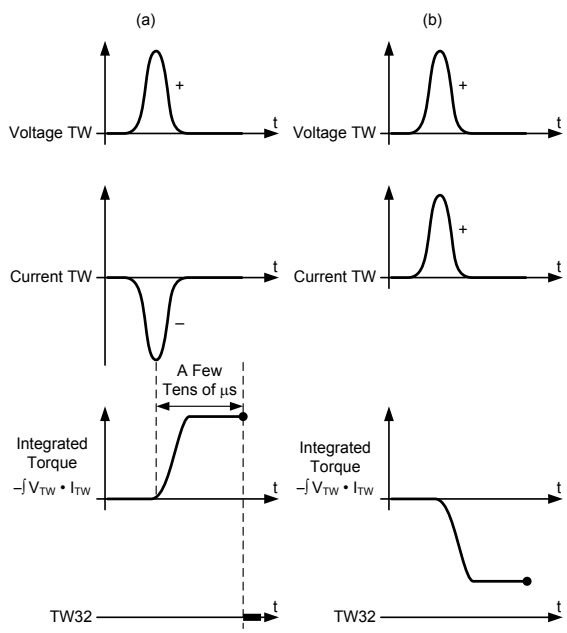

Fig. 9. Voltage and current TWs for a forward (a) and reverse (b) fault [9].

To appreciate the TW32 speed, refer to Fig. 6 and observe that the TW32 elements asserted in 0.1 ms at the remote terminal (2:TW32F).

4) TW87 Differential Scheme

The TW87 differential scheme compares time-aligned current TWs at both ends of the protected line. For an external fault, a TW that entered one terminal with a given polarity leaves the other terminal with the opposite polarity exactly after the known TW line propagation time (TWLPT) (see Fig. 10a). For an internal fault, TWs of matching polarities arrive at both line terminals with a time separation that is less than the TWLPT (see Fig. 10b). To realize the TW87 scheme, the time-domain relay [3] extracts TWs from the local and remote currents and identifies the first TW for each. It then searches for the exiting TW from the local and remote currents arriving at the opposite line terminal after the TWLPT. The relay then calculates the operating and restraining signals from the first TW and the exiting TW [5]. The TW87 logic applies a factory-selected magnitude pickup level and security slope and provides an overcurrent trip supervision threshold for the user.

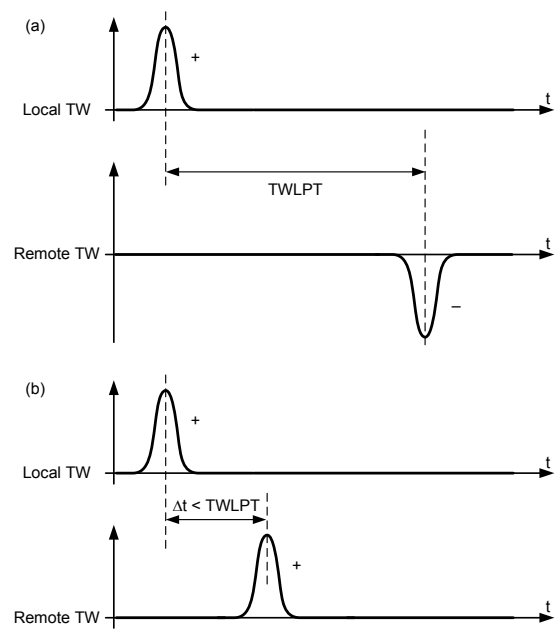

Fig. 10. Current TW timing and polarities for external (a) and internal (b) faults [9].

Fig. 11 shows a fault record for a single-line-to-ground fault on a 115 kV, 20.65 mi line in a 60 Hz system (TWLPT is 113.5 μs). The fault was 9.242 mi from the local terminal. The TW87 scheme requires a direct fiber channel, which brings the extra benefit of low communications latency. Additionally, in this case, it used relatively low overcurrent supervision settings (fast release from the overcurrent elements). As a result, it operated in 0.9 ms at both the local and remote terminals. Fig. 12 shows the first current TWs for the local and remote terminal of the line (compare with Fig. 10b).

The relay in [3] that uses these new line protection principles has a field track record of operating times in the range of 2 – 5 ms, considerably below the 0.5-cycle reference relay operating time in the breaker standards [1] and [2].

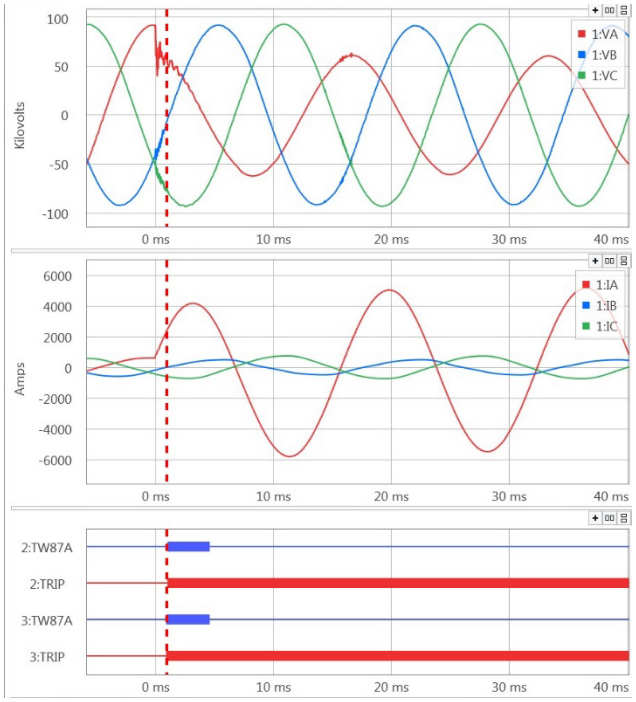

Fig. 11. Field case example for the TW87 operation. Labels 1 and 2 correspond to the local terminal, and label 3 corresponds to the remote terminal.

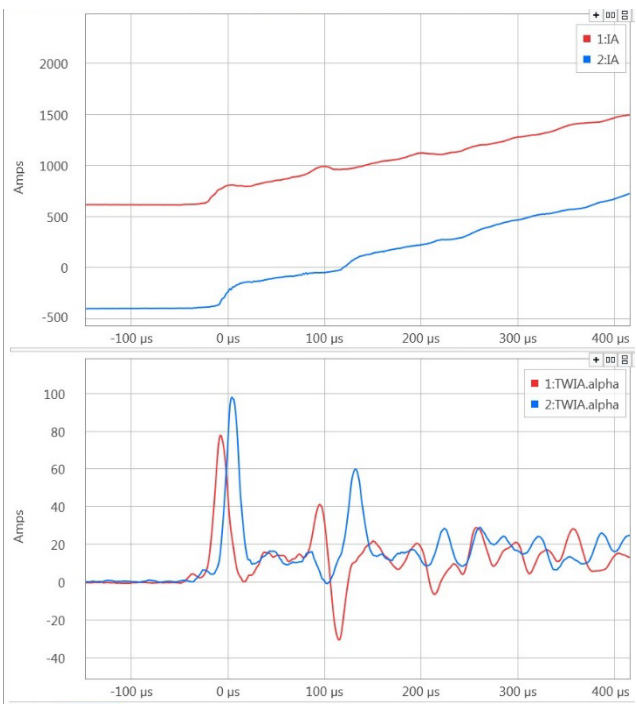

Fig. 12. Local and remote currents (top) and traveling waves (bottom) for the case of Fig. 11.

D. Protection Misoperations and Breaker Ratings

Finally, we need to consider the case of relay misoperations. Modern microprocessor-based relays incorporate extensive self-monitoring to detect any internal failures in both hardware and data integrity, and – upon a failure – they fall back gracefully without misoperation while setting an alarm to ensure proper maintenance attention. Still, there is a non-zero probability, even if very low, that a relay may misoperate due to an internal problem or because of a setting or logic error. We may argue that a misoperation is more probable during a fault condition than during normal steady-state conditions. Therefore, an extremely low, yet not zero, probability exists that a breaker may be tripped a fraction of a millisecond into a fault if a relay misoperates.

Any misoperation normally triggers an investigation and a corrective action. However, an important question is this: Shall a relay misoperation be allowed to push a breaker beyond its rating, risking breaker failure and resulting in a beaker failure trip and a larger outage, not to mention the cost, labor, and operational inconvenience of losing a breaker? In this respect, we strongly advocate having enough margin in the breaker ratings to cover the low-probability case of a relay misoperation at the very beginning of a heavy fault with a fully offset (asymmetrical) current.

V. Rating a Circuit Breaker for the Relay Operating Time

A. Derating Formulas for Relay Operating Time

To derive a derating formula accounting for an arbitrary relay operating time, we follow the S-factor (2) regarding the asymmetrical current rating for a breaker:

$$I_{RATED} = S \cdot I_{SYM} = I_{SYM}\sqrt{1 + 2\left(e^{-\frac{t_{PART}}{T_{DC}}}\right)^2} \qquad (5)$$

where:

I_{RATED} is the rated breaker asymmetrical interrupting current,

I_{SYM} is the rated breaker symmetrical interrupting current,

t_{PART} is the breaker contact parting time,

T_{DC} is the dc offset time constant (depends on the X/R ratio).

Equation (5) effectively specifies an extra margin that is required for the asymmetrical rating as compared with the symmetrical rating for any given contact parting time and dc offset time constant. Note that the value in the square root is higher than one, making I_{RATED} higher than I_{SYM}. This means that to safely interrupt the ac component of I_{SYM} under the presence of a fully offset dc component with a time constant T_{DC}, the breaker needs to be rated such that $I_{RATED} > I_{SYM}$. Or conversely, one can claim that a breaker with the symmetrical rating of I_{SYM} has the rating of I_{SYM} / S for asymmetrical conditions.

We divide the contact parting time into two components: the relay operating time (t_{REL}) and the breaker mechanical time (t_{MECH}), and rewrite (5) as follows:

$$I_{RATED} = I_{SYM}\sqrt{1 + 2\left(e^{-\frac{t_{REL}+t_{MECH}}{T_{DC}}}\right)^2} \qquad (6)$$

IEEE Standard C37.04 [1] asks the breaker manufacturers to use 0.5 cycle for the relay operating time (t_{REL} = 0.5 cycle) and 45 ms (corresponding to X/R = 17 for 60 Hz systems) for the

dc offset time constant (T_{DC} = 45 ms or 2.71 cycles). Knowing their symmetrical capability (I_{SYM}) and the mechanical time (t_{MECH}), the manufacturers specify and test the asymmetrical rating (I_{RATED}) that accounts for the reference relay operating time and the reference X/R ratio.

We can use (6) and calculate a derating factor: a ratio of the breaker interrupting rating at an arbitrary relay operating time, t_{REL}, and the nameplate rating applicable to relays that operate in 0.5 cycle ($t_{0.5}$ = 0.5 cycle).

$$I_{RATED(0.5cycle)} = I_{SYM}\sqrt{1+2\left(e^{-\frac{t_{0.5}+t_{MECH}}{T_{DC}}}\right)^2} \quad (7)$$

$$I_{RATED(t_{REL})} = I_{SYM}\sqrt{1+2\left(e^{-\frac{t_{REL}+t_{MECH}}{T_{DC}}}\right)^2} \quad (8)$$

The ratio of the interrupting current for an arbitrary relay operating time to the interrupting current for the reference 0.5-cycle relay operating time is as follows:

$$R = \frac{I_{RATED(t_{REL})}}{I_{RATED(0.5cycle)}} = \sqrt{\frac{1+2\left(e^{-\frac{t_{REL}+t_{MECH}}{T_{DC}}}\right)^2}{1+2\left(e^{-\frac{t_{0.5}+t_{MECH}}{T_{DC}}}\right)^2}} \quad (9)$$

Fig. 13 plots the R-factor for relay operating times between 2 ms and 8 ms, and for three typical breaker mechanical times of 13 ms (two-cycle breaker), 30 ms (three-cycle breaker) and 63 ms (five-cycle breaker). The figure assumes the reference X/R ratio of 17 (T_{DC} = 45 ms in 60 Hz systems). Section V, Subsection B explains the method for estimating the breaker mechanical time.

We obtain R below 1 for the relay operating times shorter than 0.5 cycle. R < 1 means the breaker lost some capability because of "fast" tripping. The 1 – R value is the "penalty" for the relay operating in less than 0.5 cycle.

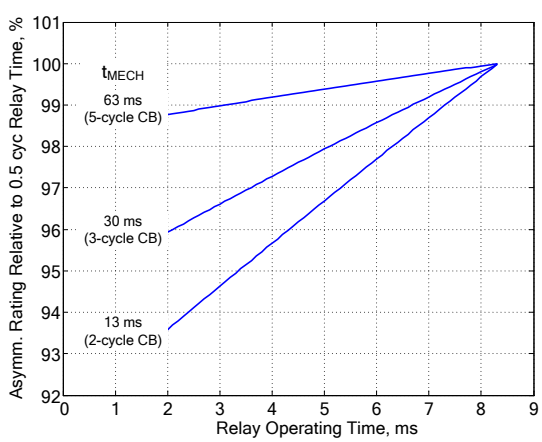

Fig. 13. Derating curves accounting for fast relay operation for an X/R of 17 in a 60 Hz system.

For example, a breaker with a 30 ms mechanical time (a three-cycle breaker) tripped in 3 ms and lost about 3.5 percent of its rating. A breaker with a 13 ms mechanical time (two-cycle breaker) tripped in 2 ms and lost about 6.5 percent of its rating (a very extreme case for both the relay and the breaker). A five-cycle breaker with a 63 ms mechanical time tripped in 2 ms and lost about 1 percent of its rating.

B. Estimating the Breaker Mechanical Time

To apply the derating formula (9), one needs to know the mechanical time in (9). You can calculate the mechanical time from the breaker interrupting time by subtracting the arcing time with margin. You can approximate the arcing time by adding the time between consecutive zero-crossings of 0.5 cycle (8.3 ms), accounting for the scatter of zero-crossings between all three phases during a three-phase fault (4.2 ms), and adding an extra margin. In practice, at maximum fault currents, a breaker needs to part its contacts 12 – 15 ms before its rated interrupting time to develop sufficient interrupter pressure to interrupt the highest current faults. Often, a 20 ms arcing interval is used for safety. In other words, a two-cycle breaker has a mechanical time of approximately 33 ms – 20 ms = 13 ms, and a five-cycle breaker has a mechanical time of about 63 ms.

Another way to approximate the breaker mechanical time is to use the symmetrical rating, if known. We can use (6) and solve it for the mechanical time as follows:

$$t_{MECH} = -\frac{T_{DC}}{2}\cdot\ln\left(0.5\left(\left(\frac{I_{RATED}}{I_{SYM}}\right)^2-1\right)\right) - 0.5\text{ cyc} \quad (10)$$

where ln is the natural (base e) logarithm.

For example, for the asymmetrical rating requirement of 1.25 times the symmetrical rating in a 60 Hz system with an X/R of 17, the mechanical time is about 20 ms; for the asymmetrical rating requirement of 1.3 times the symmetrical rating, the mechanical time is about 16 ms; for the asymmetrical rating requirement of 1.1 times the symmetrical rating, the mechanical time is about 42 ms.

You can also contact your breaker manufacturer to obtain a more precise estimate of the mechanical time.

Note that slow breakers do not need or have much of an oversizing factor for the dc component because the arc appears when the dc offset already decayed to a large degree.

C. Impact of the X/R Ratio and Mechanical Time

The derating factor R (9) includes three variables:

- Relay operating time, t_{REL}.
- DC offset time constant that depends on the X/R ratio, T_{DC}.
- Breaker mechanical time, t_{MECH}.

The impact of the relay operating time on the breaker rating varies depending on the two other factors. Fig. 13 plots the derating curves for the reference X/R ratio of 17 and three breaker mechanical times. Fig. 14 and Fig. 15 plot the derating curves for time constant values of 100 ms (X/R of 37.7 in a 60 Hz system) and 25 ms (X/R of 9.4 in a 60 Hz system), respectively. The three plots show derating factors for the relay

operating time, assuming that the X/R ratios of 17, 37.7, and 9.4, respectively, do not change. Should the X/R ratio change, the breaker shall be further derated.

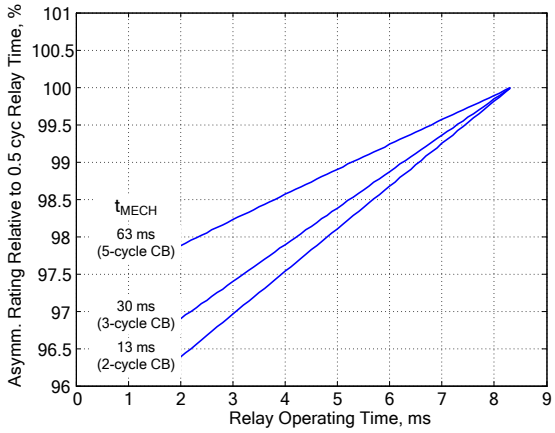

Fig. 14. Derating curves accounting for fast relay operation for an X/R of 37.7 (100 ms time constant) in a 60 Hz system.

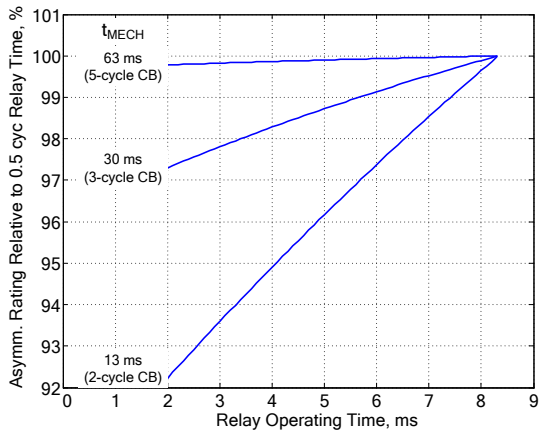

Fig. 15. Derating curves accounting for fast relay operation for an X/R of 9.4 (25 ms time constant) in a 60 Hz system.

The plots in Fig. 14 and Fig. 15 may seem counterintuitive at first: the impact of fast tripping for systems with long time constants is smaller than for systems with short time constants.

The long time constant case in Fig. 14 (large X/R) is less "punishing" for breakers tripped from fast relays, because the long decay of the dc component is the dominating factor in the rating, and the relay operating time becomes a secondary factor. In other words, the dc component is approximately as high when the relay operates very fast (such as in 2 ms) as when it operates at the reference time of 0.5 cycle.

The short time constant case in Fig. 15 seems to be more "punishing" for very fast relays, but the derating does not matter that much. Breakers are rated for the standard time constant. When operated in a system with a short time constant, these breakers gain some extra margin in rating due to the fast dc decay, and that margin is removed by relay operation faster than 0.5 cycle.

D. "Fast" Relays and "Slow" Relays

So far, we have considered relay operating times faster than the reference 0.5-cycle value. Fig. 16 plots the derating curves for relay operating times both faster and slower than 0.5 cycle for three sample breaker mechanical times.

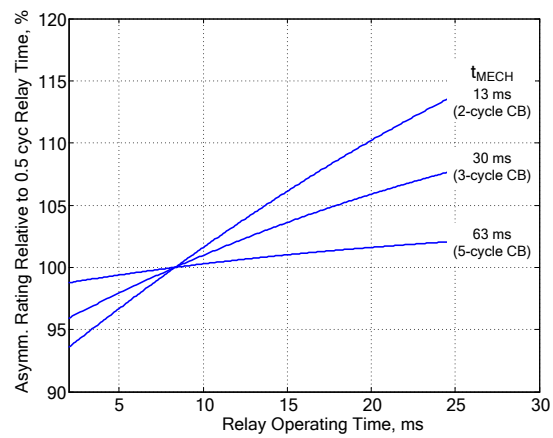

Fig. 16. Derating curves accounting for relay operation time faster and slower than the reference 0.5 cycle for an X/R of 17 (45 ms time constant) in a 60 Hz system.

For example, when the breaker mechanical time is 30 ms (a three-cycle breaker), a 2 ms relay operating time "penalizes" the breaker rating by about 4 percent compared with the nameplate. A "slow" relay operating in 20 ms "rewards" the breaker with the extra 7 percent compared with the nameplate. As we can see, the impact of the relay operating time in both directions – below and above the assumed 0.5 cycle – is not that dramatic. Also, it should be noted that this apparently higher-rated capability when using slow relays only applies to the fully asymmetrical bus or terminal fault. Other test duties, such as the short line fault test, are not affected by this change in dc asymmetry. This higher capability from a slow relay operation becomes an additional margin rather than a true increase in the rated capability.

However, if one intentionally (or unknowingly) benefits from the slow protection time premium, one may see some issues during occasional fast tripping or after retrofitting protective relays. For example, assume a breaker with a 30 ms mechanical time is marginal when operated from a 20 ms relay. When one retrofits the 20 ms relay with a 2 ms relay, one would lose +7% – (–4%) = 11% of the asymmetrical rating in this example. The 11 percent is still within the 20 percent margin recommended for breakers. However, if this breaker does not have at least an 11 percent margin, it may have issues when it is tripped in 2 ms as compared to 20 ms.

E. Is Derating for Relays Faster Than 0.5 Cycle Needed?

An ac breaker can interrupt only at the natural current zero crossing. For a fully offset current, the first current zero crossing occurs just before one full cycle (see Fig. 17). Assume that the shortest breaker mechanical time is 0.5 cycle. If we assume the relay operating time to be zero, we may conclude that this breaker can interrupt at the first zero crossing and the

interruption will be concerned with the level of the first current peak. This constitutes the absolute worst-case scenario.

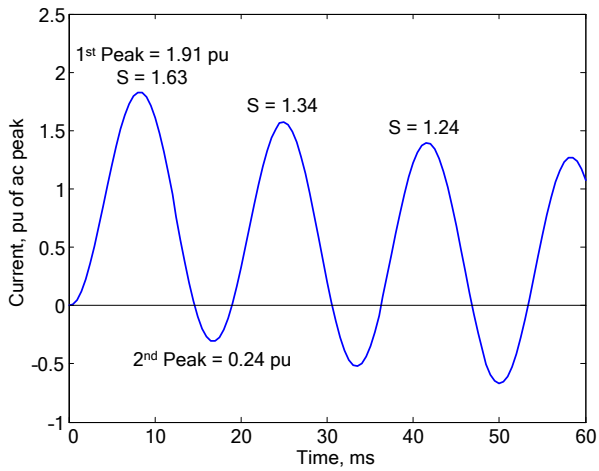

Fig. 17. Illustration of why the third current peak is critical for the asymmetrical breaker rating.

The first current peak occurs 0.25 – 0.5 cycle into the fault (0.25 cycle for symmetrical current and 0.5 cycle for a fully offset current; assume a more stringent case of 0.25 cycle in this analysis). At the time, assuming the standard X/R ratio (a dc time constant of 2.71 cycles), the dc component of a fully offset current is:

$$\mathrm{DC\%} = 100\% \cdot \mathrm{e}^{-\frac{0.25}{2.71}} = 91\%$$

and the corresponding S-factor is:

$$\mathrm{S} = \sqrt[2]{1 + 2 \cdot (0.91)^2} = 1.63$$

The above S-factor of 1.63 would ensure the absolute worst-case rating for an "instant relay" (0 ms operating time) and an "instant breaker" (mechanical time below 0.5 cycle).

If the breaker starts arcing later, it may interrupt at the second zero crossing, past the second current peak. The second current peak, however, is very small for a fully offset current. For the standard X/R of 17, the first peak occurs at 0.25 cycle and is 1.91 times the symmetrical component. The second peak occurs at 0.75 cycle and is only 0.24 times the symmetrical component (DC% is negative 76 percent at t = 0.75 cycle). Theoretically, a breaker that interrupts at the second zero crossing deals with a much smaller peak current because the dc and ac components have opposite polarities and they partially cancel. However, to interrupt at the second zero crossing, the contacts need to part considerably earlier, before the first zero crossing in this case, at the time the current is still large and falling from the previous peak. This large current in the early stage of arcing creates heat and plasma and will make it less likely to interrupt past the second peak at the second zero crossing. Also, arcing at the time of the second lower peak generates lower energy, and this may create problems for breakers that depend on arc-generated energy for interruption.

If the interruption takes place at the next (third) zero crossing, the preceding peak occurs at 1.25 cycles and is 1.63 times the symmetrical component.

With the above examples, we want to bring the following aspects to our discussion:

- The decaying dc offset in the asymmetrical current elevates the ac current peak only at every other peak. The odd peaks (first, third, fifth, and so on) are elevated while the even peaks (second, fourth, sixth, and so on) are reduced compared with the peaks of the symmetrical component.
- A breaker can interrupt only at a current zero crossing. As a result, the derating calculations may need to be rounded to a discreet time of odd current peaks (first, third, fifth, and so on).
- If arcing did not start before the first zero crossing (in the first cycle), the most intense arcing will occur at the third (not the second) current peak. The dc component elevates the third peak because the dc and ac components are of the same polarity and they add up. The dc value at the time of the third peak is lower than at the time of the second peak.
- The third current peak (assuming the standard X/R ratio) has the S-factor of 1.34, while the first peak has the S-factor of 1.63. The fifth peak occurs at 1.75 cycles and has an S-factor of 1.24.
- If the relay operating time is such that arcing starts before the first zero crossing, the application calls for an S-factor of 1.63. If relay operating time is such that arcing starts after the first zero crossing but sufficiently before the second zero crossing, the application calls for an S-factor of 1.34. If relay operating time is such that arcing starts after the second zero crossing but sufficiently before the third zero crossing, the application calls for an S-factor of 1.24.

This discussion may explain why we do not have field cases of breaker failures for breakers properly rated for 0.5-cycle relay operation when actuated from SOTF relays, fast bus differential relays, or during relay misoperations. We are aware of breaker problems after faster relays have been installed. However, those problems have roots in insufficient breaker ratings with respect to the 0.5-cycle standard relay operating time and not in the actual relay operating times being faster than 0.5 cycle.

VI. Conclusions

This paper explains the impact of the fault current dc component on the breaker asymmetrical current interrupting rating. The asymmetrical rating is driven by the current dc component level at the time of contact parting. The longer the dc time constant, the higher the dc value at the time of contact parting, and the harder it will be for the breaker to interrupt the current. Similarly, the faster the relay, the higher the dc value

at the time of contact parting, and the harder it will be for the breaker. At the same time, the slower the breaker, the smaller the dc value at the time of contact parting, the easier the current interrupting process, and the smaller the impact of the relay operating time on this process.

We developed a simple breaker derating formula that accounts for the relay operating time and the dc time constant being different from the commonly used reference values of 0.5 cycle and 45 ms, respectively.

To apply the derating formula, you need to estimate or find the breaker mechanical time. We included information on how to approximate the mechanical time based on other breaker data available.

The 0.5 cycle "worst-case" relay operating time that the breaker standards use as a reference for specifying the asymmetrical breaker rating is an arbitrary value. We described several protection schemes, as well as new line protection principles (based on incremental quantities and traveling waves) that provide operating times considerably smaller than 0.5 cycle. Breaker practitioners know how to derate a breaker for operating conditions that are different than the IEEE Standard C37.04 reference. Today, with ultra-high-speed relays, these derating calculations may include the relay operating time.

If we follow the IEEE Standard C37.04 language literarily, we conclude that there is some small "loss" of the asymmetrical breaker rating due to relay operation faster than 0.5 cycle. A 2 ms operating time in a 60 Hz system with an X/R of 17 lowers the asymmetrical breaker rating by only 3 percent (for slow breakers) and 7 percent (for very fast breakers). These numbers are below half the recommended 20 percent breaker margin. In systems with a large X/R ratio, the loss of rating is very small as the breaker is exposed to large dc offset regardless of how "fast" or "slowly" it is tripped.

Given the mechanical inertia of a breaker, a typical breaker is concerned only with the third current peak from the point of view of the worst-case scenario for the asymmetrical rating. A typical breaker will part its contacts for third current peak if actuated from a 0.5-cycle relay or from a much faster relay. Therefore, we suspect that derating of the asymmetrical breaker ratings for relay operating times below 0.5 cycle is not necessary, unless a breaker is extremely fast. A very fast breaker when tripped by an ultra-high-speed relay may start contact arcing when the current is just past the first peak. We advocate that the future revisions of the breaker standards provide clarifications in this respect.

Still, we strongly recommend following the 20 percent margin in breaker ratings. Breakers are expensive assets and their failures have serious power system consequences.

VII. References

[1] C37.04-1999 (R2006) IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers.

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[3] SEL-T400L Time-Domain Line Protection Instruction Manual. Available: https://selinc.com.

[4] R. D. Garzon, *High Voltage Circuit Breakers. Design and Application*, Marcel Dekker, New York, NY, 1997.

[5] E. O. Schweitzer, III, B. Kasztenny, A. Guzmán, V. Skendzic, and M. V. Mynam, "Speed of Line Protection – Can We Break Free of Phasor Limitations?" proceedings of the 41st Annual Western Protective Relay Conference, Spokane, WA, October 2014.

[6] M. Thompson, "The Power of Modern Relays Enables Fundamental Changes in Protection and Control System Design," proceedings of the 60th Annual Conference for Protective Relay Engineers, College Station, TX, March 2007.

[7] A. Guzmán, C. Labuschagne, B.-L. Qin, "Reliable Busbar and Breaker Failure Protection With Advanced Zone Selection," proceedings of the 31st Annual Western Protective Relay Conference, Spokane, WA, October 2004.

[8] M. Thompson, B. Kasztenny, D. Taylor, "Time-Domain Elements Optimize the Security and Performance of Transformer Protection," proceedings of the 71st Annual Conference for Protective Relay Engineers, College Station, TX, March 2018.

[9] B. Kasztenny, A. Guzmán, N. Fischer, M. V. Mynam, and D. Taylor, "Practical Setting Considerations for Protective Relays That Use Incremental Quantities and Traveling Waves," proceedings of the 43rd Annual Western Protective Relay Conference, Spokane, WA, October 2016.

VIII. Biographies

Bogdan Kasztenny has specialized and worked in power system protection and control since 1989. In his decade-long academic career, Dr. Kasztenny taught power system and signal processing courses at several universities and conducted applied research for several relay manufacturers. Since 1999, Bogdan has designed, applied, and supported protection, control, and fault locating products with their global installed base counted in thousands of installations. Since 2009, Bogdan has been with Schweitzer Engineering Laboratories, Inc. where he works on product research and development. Bogdan is an IEEE Fellow, a Senior Fulbright Fellow, a Canadian representative of the CIGRE Study Committee B5, and a registered professional engineer in the province of Ontario. Bogdan has served on the Western Protective Relay Conference Program Committee since 2011 and on the Developments in Power System Protection Conference Program Committee since 2015. Bogdan has authored over 200 technical papers and holds over 30 patents.

Joe Rostron, P.E., Senior Member, Life Member, IEEE, has 48 years of experience with advanced high-voltage technology and holds 48 patents. He is currently the Sr. V.P. of Technology Development at Southern States LLC, Hampton, Georgia, U.S.A. Joe was recognized as Outstanding Inventor in 2008 by Southern States. He has previously worked at Westinghouse, ABB, and Siemens in various engineering and development related positions. Joe is also a member of ASME. Joe is the Past Vice Chairman of the Quality and Reliability IEEE Switchgear Subcommittee. He graduated with a BSME from Washington State University and an MBA from the University of Pittsburgh. He is a registered professional engineer in the state of Pennsylvania.