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Principles of Transformer Differential Protection and Existing Problem Analysis

1.1 Introduction

With the development of the electric power industry, large capacity power transformers are more and more widely applied in power systems. As the heart of the whole power system, the performance of the transformer directly affects the continuous and stable operation of the whole power system. In particular, once a modern transformer of large capacity, high voltage, high cost and complicated structure is destroyed by a fault, a series of problems will emerge, such as wide-ranging impact, difficult and lengthy maintenance, and great economic loss. Statistics show that during the years 2001–2005, the average correct operating rate of transformers 220 kV and above is only up to 79.97%, far below the correct operating rate of line protection (more than 99%).

Differential protection is one of the foremost protection schemes used in the power transformer. The theoretical foundation of differential protection is Kirchhoff’s current law (KCL), which is applied successfully in the protection of transmission lines and generators. However, there are many problems when it is necessary to identify transformer internal faults under various complicated operation conditions [1]. From the perspective of an electric circuit, the transformer’s primary and secondary windings cannot be treated as the same node, with the voltage on each side being unequal. Besides, the two sides are not physically linked. In terms of basic principle, transformer differential protection is based on the balance of the steady magnetic circuit. However, this balance will be destroyed during the transient process and can only be rebuilt after the transient process is finished. Therefore, many unfavourable factors need to be taken into account in the implementation of transformer differential protection:

- Matching and error of the current transformer (CT) ratio.
- Transformer tap change.
- Transfer error of the CT increases during the transient process of the external fault current.
- Single-phase earth fault on the transformer’s high voltage side via high resistance.
- Inter-turn short circuit with outgoing current.
- The magnetizing inrush.

With respect to the scenarios listed above, solutions to the first five mainly rely on the features of the differential protection. The tripping resulting from the inrush current needs to be blocked for the purpose
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of preventing mal-operation. In this section, various problems in current differential protection principles and inrush current blocking schemes are firstly studied and discussed. Then, some novel principles for transformer main protection are proposed and analyzed. Simulation and dynamic tests are carried out to verify the validity and feasibility of the novel principles. By comparative research, the development route of the transformer main protection technology is given.

Compared with EHV (Extra High Voltage) power systems, the electromagnetic environment of UHV (Ultra High Voltage) systems is more complex. Meanwhile, the configuration and parameters of an UHV transformer differ from an EHV transformer. In this case, the preconditions of applying transformer differential protection correctly rest with the modelling of the UHV power transformer reasonably and appropriate analysis of corresponding electromagnetic transients. The autotransformer is the main type of UHV transformer. However, the model of the autotransformer is not available in most simulation software. An ordinary countermeasure is to replace the autotransformer by the common transformer when executing electromagnetic transient simulations. In this case, the effect of magnetic coupling can be included but the electric relationship between the primary side and the secondary side cannot be involved. One of the existing models adopts the flux linkage as the state variable and includes the nonlinearity of the transformer core. It is clear in terms of concept but too complex to perform in many cases. In contrast, a new transient simulation model of the three-phase autotransformer is described, in which the controlled voltage and current sources are developed with the modified damping trapezoidal method, which is engaged to form the synthetic simulation model. In this case, both the efficiency and the precision of simulations are improved. However, this type of model will be more reasonable if it takes into account the nonlinearity of magnetizing impedance. Furthermore, the electromagnetic transient simulations in the UHV electromagnetic environment are new challenges, especially when including the UHV transmission line with distributed parameters.

Differential protection is usually the main protection of most power transformers. The key problem for the differential protection is how to distinguish between the inrush caused by unwanted tripping or clearing the external fault and fault currents rapidly [2–4]. The traditional methods of identifying the inrush are based on the theories of second harmonic restraint and dead angle. The flux saturation point becomes lower with the improvement of iron materials. The percentage of the second harmonic in the three-phase inrush current is probably lower than 15% in the case of higher residual magnetism and initial fault current satisfying certain constrains; the lowest might be under 7% with the relative dead angle smaller than 30°. The transformer differential protection cannot avoid the mal-operation regardless of whether second harmonic restraint and dead angle based blocking schemes are adopted. The theory of identifying the inrush using currents and voltages faces the problem of low sensitivity because of the difficulty of acquiring precisely the parameters of transformers. On the other hand, if the percentage of the second harmonic within the fault current is greater than 15%, this will cause a time delay in tripping of the protection based on the second harmonic criterion. This is due to the long-distance distributed capacitance and series compensation capacitance resonance in the high voltage power systems. The percentage of the harmonic will be larger if the characteristic of CT is not good (easy to saturate) and the differential protection cannot operate with the restraint ratio of 15%. Therefore, it is necessary to find a new criterion to identify the inrush for optimizing the characteristic of the differential protection of the power transformers.

1.2 Fundamentals of Transformer Differential Protection

1.2.1 Transformer Faults

Transformers are used widely in a variety of applications, from small-size distribution transformers serving one or more users to very large units that are the essential parts of the bulk power system. Moreover, a power transformer has a variety of features, including tap changers, phase shifters, and multiple windings, which requires special consideration in the protective system design.
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Transformer faults are categorized into two classes: external faults and internal faults.

External faults are those that occur outside the transformer. These hazards present stresses on the transformer that may be of concern and may shorten the transformer life. These faults include: overloads; overvoltage; underfrequency; and external system short circuits. Most of the foregoing conditions are often ignored in specifying transformer relay protection, depending on how critical the transformer is and its importance in the system. The exception is protection against overfluxing, which may be provided by devices called ‘volts per hertz’ relays that detect either high voltage or underfrequency, or both, and will disconnect the transformer if these quantities exceed a given limit, which is usually 1.1 per unit.

Internal faults are those that occur within the transformer protection zone. This classification includes not only faults within the transformer enclosure but also external faults that occur inside the current transformer (CT) locations. Transformer internal faults are divided into two classifications for discussion; incipient faults and active faults.

Incipient faults are those that develop slowly but which may develop into major faults if the cause is not detected and corrected. They are of three kinds – transformer overheating, overfluxing, or overpressure – and usually develop slowly, often in the form of a gradual deterioration of insulation due to some causes. This deterioration may eventually become serious enough to cause a major arcing fault that will be detected by protective relays. If the condition can be detected before major damage occurs, the needed repairs can often be made more quickly and the unit placed back into service without a prolonged outage. Major damage may require shipping the unit to a manufacturing site for extensive repair, which results in an extended outage period.

Active faults are caused by the breakdown in insulation or other components that create a sudden stress situation that requires prompt action to limit the damage and prevent further destructive action. They occur suddenly and usually require fast action by protective relays to disconnect the transformer from the power system and limit the damage to the unit. For the most part, these faults are short circuits in the transformer, but other difficulties can also be cited that require prompt action of some kind. The following classifications of active faults are considered:

1. Short circuits in Y-connected windings
   (a) Grounded through a resistance
   (b) Solidly grounded
   (c) Ungrounded.
2. Short circuits in Δ-connected windings.
4. Turn-to-turn short circuits.
5. Core faults.
6. Tank faults.

1.2.2 Differential Protection of Transformers

The most common method of transformer protection uses the percentage differential relay as the primary protection, especially where speed of fault clearing is considered important. The trend in standards for reduced fault-withstand time in power transformers requires that fast clearing of transformer faults be emphasized.

As shown in Figure 1.1, \( I_1 \) and \( I_2 \) represent the transformer primary currents and \( I'_1 \) and \( I'_2 \) represent the corresponding secondary currents. Differential current in the relay KD can be given by:

\[
I_r = I'_1 + I'_2
\]  

(1.1)

The operating criterion is as follows:

\[
I_r \geq I_{set}
\]  

(1.2)
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Figure 1.1 The wiring diagram of differential protection for a double winding transformer

$I_{set}$ means the operation current and $I_r = \sqrt{\bar{I}_1^2 + \bar{I}_2^2}$ represents the root mean square (RMS) value of the differential current.

If setting transformer ratio $n_T = U_1 / U_2$, Equation (1.1) can be rewritten as:

$$I_r = \frac{I_2}{n_{TA2}} + \frac{I_1}{n_{TA1}}$$

(1.3)

$$I_r = \frac{n_T I_1 + I_2}{n_{TA2}} + \left(1 - \frac{n_{TA1} n_T}{n_{TA2}}\right) \frac{I_1}{n_{TA1}}$$

(1.4)

If $\frac{n_{TA1}}{n_{TA2}} = n_T$, we can know that $I_r = \frac{n_T I_1 + I_2}{n_{TA2}}$. Having ignored the transformer loss, the differential current $I_r$ will be zero during normal operation or when experiencing transformer external faults. In this case, the protection will not activate. When an internal fault exists, it will produce an additional fault current, which makes the differential protection operate.

We always use three-winding transformers in the real power system, usually with Y/Δ-11 connection (Figure 1.2).

In Figure 1.2, $i_a, i_b, i_c$ represent the currents on the windings and $i_A, i_B, i_C$ represent the currents on the Y-windings; $u_a, u_b, u_c$ represent the voltages of the windings and $u_A, u_B, u_C$ represent the voltages of the Y windings; $i_{LA}, i_{LB}, i_{LC}$ represent line currents of phase A, B, C on the windings.

For the winding differential protection principle, the differential current between the two sides can be calculated according to Figure 1.2:

$$\begin{bmatrix} I_{da} \\ I_{db} \\ I_{dc} \end{bmatrix} = \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} + K \begin{bmatrix} 1 & 0 & 0 \\ 0 & 1 & 0 \\ 0 & 0 & 1 \end{bmatrix} \begin{bmatrix} I_A \\ I_B \\ I_C \end{bmatrix}$$

(1.5)

In Equation (1.5), $K = \frac{6Y}{\sqrt{3}U_D} = \frac{6Y}{U_D}$.

Figure 1.2 Three-phase transformer with Y/Δ-11 connection
1.2.3 The Unbalanced Current and Measures to Eliminate Its Effect

Due to differences in transformer ratios and CT accuracy, unbalanced current may exist in the CT secondary currents during external faults which could influence differential protection’s correct operation.

There are three sources of error that tend to cause unbalanced currents:

1. Tap changing in the power transformer
2. Mismatch between CT currents and relay tap ratings.
3. Differences in accuracy of the CTs on either side of the transformer bank.

As illustrated, the unbalanced current produced by the difference of transformation ratio and transformer error is related to the through current caused by transformer external faults. With an increase in the through current, the unbalanced current also increases. This feature is the basis of the operating principle of the differential relay with restrained characteristics. When a restraint current, which can reflect the size of transformer, is introduced, the operating current of the relay will not be set to avoid the maximum through current ($I_{k \cdot \text{max}}$) but will be automatically adjusted according to the restraint current.

For a two-winding transformer, since $I_2 = -I_1$ (when an external fault occurs), it can be concluded that $I_{\text{res}} = I_1$. Besides, we have $I_{\text{unb}} = f(I_{\text{res}})$, since the unbalanced current is related to the fault current. Hence, the operation equation of the differential relay with restrained characteristics is given by $I_r > K_{\text{rel}}f(I_{\text{res}})$, where $K_{\text{rel}}$ is the reliability coefficient.

The relationship between the differential current ($I_r$) and restraint current ($I_{\text{res}}$) is demonstrated in Figure 1.3. Obviously the differential relay will act only when the differential current is above the curve of $K_{\text{rel}}f(I_{\text{res}})$. So the curve of $K_{\text{rel}}f(I_{\text{res}})$ is defined as the restrained characteristic of the differential relay. The area above the curve is the action area while the area below is the restraint area.

Figure 1.3 shows that the curve $K_{\text{rel}}f(I_{\text{res}})$ is a monotonously rising function. When $I_{\text{res}}$ is small, the transformer is unsaturated, therefore the curve $K_{\text{rel}}f(I_{\text{res}})$ is in proportion to $I_{\text{res}}$. As $I_{\text{res}}$ increases and becomes large enough to set the transformer saturated, the changing rate of curve $K_{\text{rel}}f(I_{\text{res}})$ will increase, thus the curve becomes nonlinear.

Since the transformer saturation depends on many factors, the nonlinear part of the restrained characteristic is difficult to measure. Hence, the actual restrained characteristic must be simplified. Generally in differential protection, the ‘two broken line’ characteristic is widely used, with a straight line parallel to the coordinate axis and an oblique line represented by $I_{\text{set.r}}$. In Figure 1.3, the oblique line intersects with the horizontal line at point g and with the curve $K_{\text{rel}}f(I_{\text{res}})$ at point a. In correspondence to point g, the action current is the minimum action current; the restraint current corresponding to the action current is defined as the inflection point current. When $I_{\text{set.r}} < I_{\text{res.max}}$, $I_{\text{set.r}}$ is less than $K_{\text{rel}}f(I_{\text{res}})$ permanently, this ensures that the differential relay will not mal-operate under any external fault. However, this leads to decrease of the protection sensitivity under internal faults. The unbalanced current, such as the excitation current and noise caused by the restraint current in measurement circuit, also requires the setting

![Figure 1.3 The restrained characteristic of relay](image-url)
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of a minimum action current. Otherwise mal-operation may result. The mathematical expression of the restrained characteristic is:

\[ I_{set,r} = \begin{cases} 
I_{set \text{ min}} & \text{if } I_{res} < I_{res \text{ g}} \\
K (I_{res} - I_{res \text{ g}}) + I_{set \text{ min}} & \text{if } I_{res} \geq I_{res \text{ g}}
\end{cases} \]

where \( K \) represents the slope of the restrained characteristic:

\[ K = \frac{I_{set \text{ max}} - I_{set \text{ min}}}{I_{res \text{ max}} - I_{res \text{ g}}} \]

Apart from the restraint current, the transformer inrush current will also cause unbalanced current, which also calls for discussion.

When a transformer is first energized, there is a transient inrush of current that is required to establish the magnetic field of the transformer. The mechanism of inrush generation can be seen in Figure 1.4. The reason rests with the transient saturation of flux of the transformer core due to appropriate inception angle and residual flux. This is not a fault condition and should not cause protective relays to operate. However, under certain conditions, depending on the residual flux in the transformer core, the magnitude of inrush current can be as much as 8–10 times normal full load current and can be the cause of false tripping of protective relays. This is rather serious, since it is not clear that the transformer is not internally faulted. The sensible response is, therefore, to thoroughly test the transformer before making any further attempts at energizing. This will be expensive and frustrating, especially if the tests show that the transformer is perfectly normal. Since this is such an important concept, it will be examined in some detail in order to understand the reason for high inrush current and to learn what steps can be used in protective relays to prevent their tripping due to magnetizing inrush.

There are several factors that control the magnitude and duration of the magnetizing inrush current:

- Size of the transformer bank.
- Strength of the power system to which the bank is connected.
- Resistance in the system from the equivalent source to the bank.
- Type of iron used in the transformer core.
- Prior history of the bank and the existence of residual flux.
- Conditions surrounding the energizing of the bank, for example,
  (a) Initial energizing
  (b) Recovery energizing from protective action
  (c) Sympathetic inrush in parallel transformers.

![Figure 1.4 Derivation of the inrush current wave from the excitation saturation curve](image-url)
There are several methods that have been used to prevent the tripping of a sound transformer due to large inrush currents that accompany initial energizing of the unit. The common methods used are:

1. Desensitize the relay during start-up.
2. Supervise the relay with voltage relays.
3. Add time delay.
4. Detect magnetizing inrush by observing the current harmonics.

These methods can be further described, as follows:

1. Methods have been devised to desensitize the differential relay and prevent tripping during start-up. One method parallels the operating coil with a resistor, with the resistor circuit being closed by an undervoltage relay contact. When the transformer bank is de-energized, the undervoltage relay resets, thereby closing the resistor bypass circuit. On start-up, the operating coil is bypassed until the undervoltage relay picks up, which is delayed for a suitable time.
2. Another method uses a fuse to parallel the differential relay operating coil. The fuse size is selected to withstand normal start-up currents, but internal fault currents are sufficient to blow the fuse and divert all current to the operating coil.
3. The voltage supervised relay measures the three-phase voltage as a means of differentiating between inrush current and a fault condition, a fault being detected by a depression in one of the three-phase voltages. This concept is usable for either fast or slow relays, it constitutes an improvement in the method.
4. Simply adding time delay to the differential relays during energizing the transformer is effective but must be accompanied by some method of overriding the time delay if an actual fault occurs during start-up. Usually, time delay is used in conjunction with other relay intelligence.
5. Harmonic current restraint is another method that is used. It was noted earlier that the second harmonic of the total current is almost ideal for determining whether a large inrush of current is due to initial energizing or to a sudden fault. Most differential relays use filters to detect the second, and sometimes the fifth, harmonic current and restrain tripping when this current is present.

1.3 Some Problems with Power Transformer Main Protection

1.3.1 Other Types of Power Transformer Differential Protections

1.3.1.1 Inter-Phase Differential Protection Principle

There are still some problems that exist in the winding differential protection:

- The winding current of transformers with Y/Δ-connection cannot be obtained.
- Cooperation with overcurrent protection is difficult, which will produce a protection dead zone.

Similar to the phase differential protection, the differential current of inter-phase current differential protection can be obtained:

\[
\begin{bmatrix}
I_{dA} \\
I_{dB} \\
I_{dC}
\end{bmatrix} = \begin{bmatrix}
1 & -1 & 0 \\
0 & 1 & -1 \\
-1 & 0 & 1
\end{bmatrix} \begin{bmatrix}
I_a \\
I_b \\
I_c
\end{bmatrix} + K \begin{bmatrix}
1 & -1 & 0 \\
0 & 1 & -1 \\
-1 & 0 & 1
\end{bmatrix} \begin{bmatrix}
I_A \\
I_B \\
I_C
\end{bmatrix}
\]

The disadvantage of inter-phase differential protection principle is as follows: for a three-phase transformer with Y/Δ-11 connection, when a Y-side single-phase grounding occurs, protection sensitivity will decrease. As a solution to this problem, a zero-sequence differential protection scheme is put forward in this section.
1.3.1.2 Zero-Sequence Differential Protection Principle

For single-phase high voltage large transformers, the main type of short-circuit fault is between winding to the iron core (when ground insulation is damaged), that is, single-phase grounding. Inter-phase short-circuit (in-box fault) seldom happens. Thus, single-phase grounding is carefully studied.

The constitution of zero-sequence differential protection is shown in Figure 1.5. On the Y-side of the transformer, the secondary sides of the CTs are connected to form a zero-sequence filter. Together with the secondary side of the neutral CT, the zero-sequence differential protection is formed.

Advantages of zero-sequence differential protection are:

- Relatively high sensitivity to single-phase grounding faults on the Y-side;
- The operation current is not affected by the transformer tap.
- Not directly influenced by the magnetizing inrush current.
- All CTs apply the same ratio, which is not related with the transformer ratio.

Disadvantages of zero-sequence differential protection are:

- Low (zero) sensitivity to inter-phase faults and faults on the low voltage side.
- Low sensitivity to high resistance grounding faults.
- Examination of wiring error on the secondary side is more complicated.

1.3.1.3 Split-Side Differential Protection

For phase differential protection schemes, the problem of mal-operation caused by inrush current or overexcitation always exists. Therefore, it is necessary to develop a novel transformer differential protection scheme that is not affected by either inrush current or overexcitation current. The new protection scheme is called transformer split-side differential protection in this section, the wiring diagram of which is shown in Figure 1.6.

For transport considerations, modern large capacity transformers are commonly made up of three single-phase transformers. The terminals of the windings are all led out of the shell, which facilitates the implementation of the proposed split-side differential protection. Advantages of this protection scheme are:

- Relatively high sensitivity to single-phase grounding faults.
- Not affected by the transformer tap.
- Not directly affected by the inrush current.

![Figure 1.5](image-url)  
*Figure 1.5 Connecting diagram of zero-sequence current differential protection*
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- The spilt-side differential protection being applied to large power transformers can simplify the device.
- Simple protection principle, reliable device, and convenient debugging.

Disadvantages of split-side differential protection are:

- Low (zero) sensitivity to common inter-turn faults.
- Applicable only when each winding has two terminals led out.
- The number of protection relays needed doubles.

From the above analysis, it is obvious that zero-sequence differential protection and spilt-side differential protection schemes are both superior to inter-phase differential protection in certain aspects. However, in view of the actual connection modes of transformers and the protective relaying characteristics, the inter-phase differential protection, especially longitudinal differential protection, is still most commonly used as the main protection for transformers. In longitudinal differential protection, the impact of inrush current has long been a problem that requires special measures to deal with it.

1.3.2 Research on Novel Protection Principles

With the rapid development of microcomputer technology and the wide application of the transformer main-backup-integrated protection scheme, it has become possible to conduct complex calculations within the transformer protection device using multiple electric variables. Since the transformer is a nonlinear and time-varying system, the voltage and current are two independent variables, not linearly correlated. Thus, by using both the voltage and current variables to describe the operation state of transformer, the information is more complete. Furthermore, it facilitates the search for new protection criteria of higher sensitivity and better reliability. Currently, transformer protection principles that use both the voltage and current variables mainly include: the magnetic flux characteristic principle, sequence impedance principle, loop equation principle, power differential principle and so on.

The magnetic flux characteristic principle is based on the nonlinearity of the excitation branch and has a promising application future. However, currently it is applicable only to single-phase transformer groups. For three-phase transformers with Y/Δ connection, since the internal circulation current on the Δ-side winding is difficult to measure, how the magnetic flux characteristic can be applied in this case to reflect the nonlinear characteristics of the excitation branch remains to be studied.

In the following sections, the advantages and disadvantages of the sequence impedance principle, loop equation principle and power differential principle are discussed, on the basis of which some novel principles of transformer main protection are put forward.
1.3.2.1 Sequence Impedance Principle

The sequence impedance principle is based on the changes of the transformer positive and negative sequence equivalent networks before and after the fault. With the variation of the positive and negative sequence voltage and current, the positive and negative sequence impedances felt by the relay points on both sides of the transformer can be calculated. Then, according to the direction of the calculated impedances, it can be decided whether the transformer fault is internal or external. For a convenient illustration, a two-winding transformer is taken as an example, the system model of which is shown in Figure 1.7. The protective relays are installed on both sides of the transformer and the positive direction for current is set as in the figure.

For transformer external faults, suppose a fault occurs at F1 on the transmission line. According to the positive sequence equivalent network before and after the fault, the following expression can be obtained:

\[
\begin{align*}
\frac{\Delta V_{x1}}{\Delta I_{x1}} &= -Z_{Gx1}, \\
\frac{\Delta V_{y1}}{\Delta I_{y1}} &= -(Z_{Gy1} + Z_{Line1})
\end{align*}
\]  

(1.7)

where \(\Delta V_{x1}, \Delta I_{x1}, \Delta V_{y1}\) and \(\Delta I_{y1}\) represent the variation of positive sequence voltage and current on both sides of the transformer before and after the fault; \(Z_{Gx1}\) and \(Z_{Line1}\) are the positive sequence equivalent impedance of the system on the X-side and the transmission line respectively.

Similarly, according to the negative sequence equivalent network before and after the fault, the following can be obtained:

\[
\begin{align*}
\frac{\Delta V_{x2}}{\Delta I_{x2}} &= -Z_{Gx2}, \\
\frac{\Delta V_{y2}}{\Delta I_{y2}} &= + (Z_{Gy2} + Z_{Line2})
\end{align*}
\]  

(1.8)

where \(\Delta V_{x2}, \Delta I_{x2}, \Delta V_{y2}\) and \(\Delta I_{y2}\) represent the variation of negative sequence voltage and positive sequence current on both sides of the transformer before and after the fault; \(Z_{Gx2}\) and \(Z_{Line2}\) are the negative sequence equivalent impedance of the system on the X-side and the transformer respectively.

For transformer internal faults, suppose a fault occurs at F2. Similarly, the positive and negative sequence impedances on both sides of the transformer can be calculated as shown in the following:

\[
\begin{align*}
\frac{\Delta V_{x1}}{\Delta I_{x1}} &= -Z_{Gx1}, \\
\frac{\Delta V_{y1}}{\Delta I_{y1}} &= -(Z_{Gy1} + Z_{Line1})
\end{align*}
\]  

(1.9)

\[
\begin{align*}
\frac{\Delta V_{x2}}{\Delta I_{x2}} &= -Z_{Gx2}, \\
\frac{\Delta V_{y2}}{\Delta I_{y2}} &= -(Z_{Gy2} + Z_{Line2})
\end{align*}
\]  

(1.10)

where \(Z_{Gx1}, Z_{Line1}, Z_{Line2}\) and \(Z_{Gx2}\) are the positive and negative sequence equivalent impedances of the system on the Y-side and the transmission line respectively.

It can be seen from Equations (1.7) and (1.8) that, when a transformer external fault occurs, the positive and negative sequence impedances felt by both sides of the transformer are different in direction – one positive and the other negative. And from Equations (1.9) and (1.10) it can be seen that, when a transformer internal fault occurs, the positive and negative sequence impedances felt by both sides of the transformer are the same in direction – both negative. Based on this fact, a method is put forward to distinguish between internal and external faults of the transformer (referred to as the ‘quadrant division method’ hereinafter): if the positive and negative sequence impedances on both sides of the transformer are different in direction – one located in first quadrant on the image plane and the other in the third quadrant – then the fault can be identified as an external fault; otherwise, if the positive and negative

![Figure 1.7 System model of a two-winding transformer](image-url)
sequence impedances on both sides of the transformer are the same in direction – both in the third quadrant on the image plane – then the fault can be identified as an internal fault. On the basis of the ‘quadrant division method’, the division of the image plane is revised by extending the regional boundary to the second and fourth quadrants. Simulation results show that this revision improves the reliability and sensitivity of identification to a certain degree. However, neither the ‘quadrant division method’ nor the revised method can counteract the negative influence of inrush current. Therefore, other criteria should be added to form an effective protection scheme. Furthermore, for transformer protection principles based on sequence impedance, the correct identification between the conditions of normal no-load switching and no-load switching at internal faults remains to be studied.

1.3.2.2 Loop Equation Principle

Microcomputer transformer main protection based on the loop equation principle is very different from traditional differential protection. The interference of inrush current is avoidable with this method, since it does not distinguish inrush current from the internal fault current according to the waveform characteristics of the inrush current. Moreover, this method is not affected by the connection mode of the transformer. Take a single-phase transformer as an example. The system model is shown in Figure 1.8, which can be described by the two differential equations in Equation (1.11). By eliminating the nonlinear item \( d\psi_m/dt \) in Equation (1.11), which reflects the transformer’s core flux, the two equations in Equation (1.12) are obtained.

\[
\begin{align*}
\frac{du_1}{dt} &= i_1r_1 + L_1 \frac{di_1}{dt} + \frac{d\psi_m}{dt} \\
\frac{du_2}{dt} &= i_2r_2 + L_2 \frac{di_2}{dt} + \frac{d\psi_m}{dt} \\
\frac{du_{12}}{dt} &= L_1 \frac{di_1}{dt} - L_2 \frac{di_2}{dt} \\
\frac{du_{12}}{dt} &= u_1 - u_2 - i_1r_1 + i_2r_2
\end{align*}
\]  

(1.11)  

(1.12)

In Equations (1.11) and (1.12), \( u_1 \) and \( u_2 \) are the voltages of the primary and secondary windings; \( i_1 \) and \( i_2 \) are the currents on the primary and secondary windings; \( L_1 \) and \( L_2 \) are the leakage inductances of the primary and secondary windings; \( \psi_m \) is the mutual inductance flux between the primary and secondary windings; \( r_1 \) and \( r_2 \) are the resistances of the primary and secondary windings.

When the transformer operates in the normal state, \( r_1 + r_2 = r_k \) and \( L_1 + L_2 = x_k/w \), where \( r_k \) and \( x_k \) are the winding resistance and short-circuit reactance, respectively. By applying these two formulas to

![Figure 1.8 Two-winding single-phase transformer](image-url)
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Equation (1.12), two equivalent loop balance equations can be obtained:

\[
\begin{align*}
-u_1 + u_2 + i_2 r_2 + \frac{x_2}{w} \frac{d i_2}{d t} &= (i_1 + i_2) r_1 + L_1 \frac{d(i_1 + i_2)}{d t} \\
-u_1 - u_2 - i_1 r_1 - \frac{x_1}{w} \frac{d i_1}{d t} &= -(i_1 + i_2) r_2 - L_2 \frac{d(i_1 + i_2)}{d t}
\end{align*}
\]  

(1.13)

Since Equation (1.12) is based on the normal operation state of the transformer, it is applicable for any circumstance except for a transformer internal fault. Therefore, the validity of Equation (1.12) can be used as a criterion to direct the action of the protective relay. However, this method needs improving in the following two aspects:

1. Currently no feasible method is available to obtain the leakage inductance of each winding in real-time.
2. Even if the leakage inductance parameters can be obtained, it is still dependent on accurate internal fault data to determine the protection scheme, protection criterion and the sensitivity check methods.

Addressing the above problems, the following measures for improvement are proposed.

Based on the transformer loop equation, the equivalent instantaneous leakage inductance of each winding is established; this can reflect the variation status of the transformer leakage magnetic field. The equivalent instantaneous leakage inductance bears similar changing characteristics to the actual leakage inductance. Thus, firstly each equivalent instantaneous leakage inductance is obtained in the cases of inrush current, excessive excitation or external fault, which is a constant value. Secondly, when a fault occurs to the transformer winding, the equivalent instantaneous leakage inductance of the fault phase will change significantly, rendering an obvious difference in value from the normal leakage inductance. Such difference or variation in the value of the equivalent instantaneous leakage inductance can be used to form new transformer main protection criteria.

Establishment of Equivalent Instantaneous Leakage Inductance Parameter

Equation (1.13) contains two unknown parameters \((r_1, L_1)\), so it cannot be solved directly. However, by establishing two independent equations using data measured at different moments, it can be solved. To this end, two adjacent moments, \(t_1\) and \(t_2\), are chosen to establish the equations:

\[
\begin{align*}
 u_{121}(t_1) &= r_1 i_d(t_1) + L_1 \frac{d i_d(t_1)}{d t} \\
 c(t_2) &= r_1 i_d(t_2) + L_1 \frac{d i_d(t_2)}{d t}
\end{align*}
\]  

(1.15)

where \(u_{121} = u_1 - u_2 + i_2 r_2 + \left(\frac{x_2}{w}\right) \left(\frac{d i_2}{d t}\right)\), \(i_d = i_1 + i_2\).

In implementation, current difference can be used instead of current differential in Equations (1.15) and (1.16). To this end, three adjacent sample values (three continuous points after the digital filtering) are chosen. Suppose that \(u_{k-1}, u_k\) and \(u_{k+1}\) represent the voltage samples at \(t_{k-1}, t_k\) and \(t_{k+1}\), and that \(i_{k-1}, i_k\) and \(i_{k+1}\) represent the current samples at \(t_{k-1}, t_k\) and \(t_{k+1}\). Set \(t_1\) to be in the midst of \(t_{k-1}\) and \(t_k\), and \(t_2\) in the midst of \(t_k\) and \(t_{k+1}\), with a sampling interval between \(t_1\) and \(t_2\). Then \(u_{121}(t_1), u_{221}(t_2), i_d(t_1), i_d(t_2), d i_d(t_1)/d t\) and \(d i_d(t_2)/d t\) in Equations (1.15) and (1.16) can be expressed by interpolation of the samples:

\[
\begin{align*}
u_{121}(t_1) &= \frac{u_k + u_{k-1}}{2}, u_{121}(t_2) = \frac{u_k + u_{k+1}}{2} \\
i_d(t_1) &= \frac{i_k + i_{k-1}}{2}, i_d(t_2) = \frac{i_k + i_{k+1}}{2} \\
D_1 &= \frac{d i_d(t_1)}{d t} = \frac{i_k - i_{k-1}}{T_i}, D_2 = \frac{d i_d(t_2)}{d t} = \frac{i_{k+1} - i_k}{T_i}
\end{align*}
\]  

(1.17)

(1.18)

(1.19)
Combining Equations (1.15) and (1.16), the instantaneous leakage inductance \( L_1 \) at \( t_1 \) can be obtained, as shown in Equation (1.20). Thus, calculated instantaneous leakage inductance is based on the normal operating model of the transformer. In the case of an internal fault, since the loop equation is no longer valid, the calculated leakage inductance is not the actual measuring value but, rather, an equivalent one. Therefore, it is defined as the equivalent instantaneous leakage inductance.

\[
L_1 = u_{121}(t_1)\frac{d}{dt}i_{d}(t_2) - u_{121}(t_2)\frac{d}{dt}i_{d}(t_1)
\]

Similarly, the equivalent instantaneous leakage inductance \( L_2 \) at \( t_1 \) can be obtained:

\[
L_2 = u_{122}(t_1)\frac{d}{dt}i_{d}(t_2) - u_{122}(t_2)\frac{d}{dt}i_{d}(t_1)
\]

where \( u_{122} = -(u_1 - u_2 - i_r^x - (x_w/\omega)(di^x_1/dt)) \).

**Design of the Protection Scheme**

**Main criterion:**

After the protection starts, calculate on-line the equivalent instantaneous leakage inductance of each phase and use a \( 1/4 \) cycle length sliding data window to calculate the real-time average value of the leakage inductance. Compare the average equivalent instantaneous leakage inductances of different phases, then the protection criterion can be formed. It should be noted that the average equivalent instantaneous leakage inductance of the non-pick-up phase is represented by the normal leakage inductance of that phase.

Take the \( \Delta \)-side of a three-phase Y/\( \Delta \)-connected transformer as an example. The difference among the average equivalent instantaneous leakage inductances of the phases is described by \( \sigma_{12}^2 \) in Equation (1.22). When \( \sigma_{12}^2 > \sigma_{zd}^2 \), it can be identified as an internal fault and the protection should operate.

\[
\sigma_{12}^2 = \frac{1}{3}((L_{lae}' - L_{lbe}')^2 + (L_{lbe}' - L_{lce}')^2 + (L_{lce}' - L_{lae}')^2)
\]

where \( L_{lae}' \), \( L_{lbe}' \) and \( L_{lce}' \) represent the average equivalent instantaneous leakage inductance of each phase on the \( \Delta \)-side. If there is any phase not switched on (un-started), then its average equivalent instantaneous leakage inductance should be replaced by \( L_{lie}' \) (\( i = 1, 2, 3 \)), the normal leakage inductance of the phases on the \( \Delta \)-side.

**Auxiliary criterion:**

When a serious internal fault occurs in the transformer, the differential current will be very large, so that the calculated leakage inductances will be small in value and minor in their differences. In this case, using only the main criterion may lead to operation failure of the protection. Therefore, the conventional differential current instantaneous break protection can be introduced as an auxiliary criterion for comprehensive identification.

**Scheme Verification**

Considering the influence of different switching moments, 20 measurements are conducted for each operation state. The calculation results of each group of 20 data are listed in Table 1.1.

As shown in the \( \sigma_{12}^2 \) column of Table 1.1, the minimum value of \( \sigma_{12}^2 \) under fault conditions (except inter-phase faults) is 80.65 times the maximum value of \( \sigma_{12}^2 \) under normal no-load switching conditions. If \( \sigma_{12}^2 \) is set to be \( 10 \times (10^{-H})^2 \), then according to the main criterion, it is possible to effectively distinguish between inrush current and internal fault current (except inter-phase faults). Furthermore, with the cooperation of the auxiliary criterion, correct and reliable operation of the protective relay under various internal fault conditions can be guaranteed.
Table 1.1 Calculation results of $\sigma_2^2$ under various situations

<table>
<thead>
<tr>
<th>Operation states</th>
<th>$\sigma_2^2(\times 10^{-4} , \text{H})^2$</th>
<th>Serial number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drop</td>
<td>Normal dropping</td>
<td>0.9538–1.2152</td>
</tr>
<tr>
<td>In star side fault</td>
<td>Inter-turn</td>
<td></td>
</tr>
<tr>
<td></td>
<td>A9%</td>
<td>112.7443–125.3236</td>
</tr>
<tr>
<td></td>
<td>B18%</td>
<td>216.7854–223.7382</td>
</tr>
<tr>
<td></td>
<td>C18%</td>
<td>220.8367–231.1159</td>
</tr>
<tr>
<td>Grounding</td>
<td>A</td>
<td>197.2485–222.1532</td>
</tr>
<tr>
<td></td>
<td>B</td>
<td>148.5279–160.2373</td>
</tr>
<tr>
<td>Inter-phase</td>
<td>AB</td>
<td>1.9634–3.1248</td>
</tr>
<tr>
<td></td>
<td>BC</td>
<td>1.5586–3.0747</td>
</tr>
<tr>
<td>Star side fault under operation</td>
<td>Inter-turn</td>
<td></td>
</tr>
<tr>
<td></td>
<td>A9%</td>
<td>98.0825–111.3468</td>
</tr>
<tr>
<td></td>
<td>B18%</td>
<td>205.4478–218.4637</td>
</tr>
<tr>
<td></td>
<td>C18%</td>
<td>161.2256–172.6055</td>
</tr>
<tr>
<td>Grounding</td>
<td>A</td>
<td>212.6494–223.1037</td>
</tr>
<tr>
<td></td>
<td>B</td>
<td>155.3819–160.6530</td>
</tr>
<tr>
<td>Inter-phase</td>
<td>AB</td>
<td>1.7832–2.9875</td>
</tr>
<tr>
<td></td>
<td>BC</td>
<td>1.6329–2.8321</td>
</tr>
</tbody>
</table>

1.3.2.3 Power Differential Principle

Transformer microcomputer main protection based on the power differential principle considers the voltage and current information synthetically based on the law of energy conservation. When the transformer operates in the normal state, little active power is consumed; but when the transformer insulation is damaged, the sparkling electrical arc will consume large amounts of active power. Therefore, by detecting the amount of active power consumed, it can be decided when an internal fault occurs. The power differential principle does not rely on the waveform characteristics of the inrush current and is a novel main protection scheme. However, there are still some problems about the scheme that remain to be solved:

- This scheme is not totally free from the negative influence of the inrush current. By avoiding the charging process in the first cycle when there is inrush current, the protection judgment will be delayed.
- When there is inrush current, the copper loss is difficult to calculate accurately and the iron loss will increase, which make the value setting complicated.
- For transformers with Y/Δ connection, the current on windings of the Δ-side cannot be obtained, thus the copper loss cannot be determined, which reduces the sensitivity of protection.

In view of the above questions, based on the normal operation state loop equation of the transformer, a two-terminal network containing only the leakage inductance and winding resistance is formed in this section. By analysing the input generalized instantaneous reactive power, the essential difference between the inrush current and internal fault is further revealed.

Design of the Two-Terminal Network

Taking the double-winding single-phase transformer as an example, the two-terminal network based on the voltage and current information can be designed.
According to Equations (1.13) and (1.14), two two-terminal networks can be formed. The one containing only $r_1$ and $L_1$ is shown in Figure 1.9, which is defined as the primary side two-terminal network. The other, containing only $r_2$ and $L_2$, is shown in Figure 1.10 and is defined as the secondary side two-terminal network.

The terminal voltage of the network in Figure 1.9 is:
\[ u_{121} = u_1 - u_2 + i_2 r_1 + \frac{x_k}{w} \frac{di_2}{dt} \] \hspace{1cm} (1.23)

The terminal voltage of the network in Figure 1.10 is:
\[ u_{122} = -\left( u_1 - u_2 - i_1 r_1 - \frac{x_k}{w} \frac{di_1}{dt} \right) \] \hspace{1cm} (1.24)

In both Figures 1.9 and 1.10, the arrow represents the direction of voltage drop and the current injected into the two-terminal network is $i_d = i_1 + i_2$.

In the case of no-load switching, suppose that the secondary side of the transformer is not loaded, then a two-terminal network similar to that in Figure 1.9 can be formed according to Equation (1.12). In this case the terminal voltage is: $u_{121} = u_1 - u_2$ and the current injected into the two-terminal network is $i_1$.

Take the two-terminal network in Figure 1.9 for illustration. Although $i_d(t)$ and $u_{121}(t)$ of the input terminal are not correspondently related in the actual system, their product has the nature of instantaneous power. Thus, it can be defined as the generalized instantaneous power, that is, $S_{gy1}(t) = u_{121}(t) i_d(t)$, or in another form: $S_{gy1}(t) = \tilde{S}_{gy1}(t) + S_{gy1}(t)$, where the DC part $\tilde{S}_{gy1}$ is the generalized instantaneous power absorbed by the primary side. Similarly, the generalized instantaneous power absorbed by the secondary side $\tilde{S}_{gy2}$ can obtained. On this basis, define the difference between $\tilde{S}_{gy1}$ and the active power consumed by the normal winding resistance $r_1$ to be $P_1$, and the difference between $\tilde{S}_{gy2}$ and the active power consumed by the normal winding resistance $r_2$ to be $P_2$. Formulas to calculate $P_1$ and $P_2$ are:

\[
\begin{align*}
P_1 &= \frac{1}{T} \int_0^T \left( u_{121}(t) i_d(t) - \tilde{v}_1(t) r_1 \right) dt \\
P_2 &= \frac{1}{T} \int_0^T \left( u_{122}(t) i_d(t) - \tilde{v}_2(t) r_2 \right) dt
\end{align*}
\] \hspace{1cm} (1.25)
It can be seen from Equation (1.25) that, in the cases of the normal operating state (including no-load switching and external faults), the generalized active power absorbed by the two-terminal network is all consumed by the winding resistance, thus $P_1$ and $P_2$ are both zero (not considering various kinds of errors). But in the case of internal faults, due to the power loss of the fault branch and the fact that $P_1$ and $P_2$ are calculated with the voltage and current after the fault and the winding resistance before the fault, $P_1$ and $P_2$ will no longer be zero. By setting an appropriate threshold value, it is possible to effectively distinguish between normal operation state and fault condition.

**Principle Verification**

The dynamic simulation results of the power differential principle and the novel principle applied in various cases are shown in Table 1.2. $P_m$ represents the maximum active power in three phases. Considering the influence of different closing moments, the calculation result under every operation state is the comprehensive analysis of 20 measurements.

<table>
<thead>
<tr>
<th>Operation states</th>
<th>$P_c$/W</th>
<th>$P_m$/W</th>
<th>Serial number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal state</td>
<td>Normal switching on</td>
<td>854–1 393</td>
<td>0.76–2.2</td>
</tr>
<tr>
<td></td>
<td>Normal operation</td>
<td>309–348</td>
<td>0.53–0.96</td>
</tr>
<tr>
<td>Dropping fault</td>
<td>Star side fault</td>
<td>A2.4%</td>
<td>1 161–1 484</td>
</tr>
<tr>
<td>with faults</td>
<td>Inter-turn</td>
<td>A6.1%</td>
<td>1 659–1 827</td>
</tr>
<tr>
<td></td>
<td></td>
<td>A9%</td>
<td>2 471–2 539</td>
</tr>
<tr>
<td></td>
<td></td>
<td>B18%</td>
<td>8 363–8 432</td>
</tr>
<tr>
<td></td>
<td></td>
<td>C18%</td>
<td>8 016–8 109</td>
</tr>
<tr>
<td>Grounding</td>
<td>A</td>
<td>14 142–14 275</td>
<td>1 032–1 087</td>
</tr>
<tr>
<td></td>
<td>B</td>
<td>16 057–16 148</td>
<td>651–734</td>
</tr>
<tr>
<td>Inter-phase</td>
<td>AB</td>
<td>23 814–23 906</td>
<td>2 212–2 320</td>
</tr>
<tr>
<td></td>
<td>BC</td>
<td>25 689–25 762</td>
<td>2 146–2 199</td>
</tr>
<tr>
<td>Angle side</td>
<td>A1.8%</td>
<td>1 123–1 415</td>
<td>25–32</td>
</tr>
<tr>
<td>inter-turn fault</td>
<td>A4.5%</td>
<td>1 582–1 737</td>
<td>38–46</td>
</tr>
<tr>
<td>Fault state</td>
<td>Star side fault</td>
<td>A2.4%</td>
<td>1 098–1 1217</td>
</tr>
<tr>
<td>under operation</td>
<td>Inter-turn</td>
<td>A6.1%</td>
<td>1 769–1 895</td>
</tr>
<tr>
<td></td>
<td></td>
<td>A9%</td>
<td>2 471–2 539</td>
</tr>
<tr>
<td></td>
<td></td>
<td>B18%</td>
<td>8 363–8 432</td>
</tr>
<tr>
<td></td>
<td></td>
<td>C18%</td>
<td>8 016–8 109</td>
</tr>
<tr>
<td>Grounding</td>
<td>A</td>
<td>13 986–14 095</td>
<td>876–892</td>
</tr>
<tr>
<td></td>
<td>B</td>
<td>14 260–14 363</td>
<td>535–568</td>
</tr>
<tr>
<td>Inter-phase</td>
<td>AB</td>
<td>22 381–22 476</td>
<td>2 054–2 139</td>
</tr>
<tr>
<td></td>
<td>BC</td>
<td>23 905–24 019</td>
<td>1 963–2 017</td>
</tr>
<tr>
<td>Angle side</td>
<td>A1.8%</td>
<td>1 112–1 228</td>
<td>25–29</td>
</tr>
<tr>
<td>inter-turn fault</td>
<td>A4.5%</td>
<td>1 594–1 703</td>
<td>42–51</td>
</tr>
</tbody>
</table>
It can be seen from Table 1.2 that, for the differential active power principle, if the threshold value is set to be 2100 W (i.e. 1.5 times the maximum value of $P_c$ in the normal operation state), there will be eight cases (serial numbers 3, 4, 12, 13, 14, 15, 23 and 24) that cannot be identified.

For the proposed novel principle, the maximum value of $P_m$ in normal operation state and the minimum value of $P_m$ under fault condition are more than 10 times apart. Therefore, if the threshold value of $P_m$ is set to be 4 W (i.e. the maximum value of $P_m$ in the normal operation state), then all kinds of faults can be identified with a good redundancy.

It is thus obvious that the proposed novel principle is superior to the existing power differential principle in reliability and sensitivity.

Concerning the technology development route of transformer main protection, the principle is to ‘aim at old problems and come up with new ideas’. On one hand, with no better protection schemes coming forth, the focus should be on summarizing effective solutions and experience in the identification of inrush current and fault current, while at the same time exploring the application of new theories and new technology, in an effort to improve the performance of the current differential protection. The study topics involved in this aspect mainly include:

- Explore novel principles of transformer differential protection.
- Research on the identification of inrush current and fault current.
- Study on the recognition of CT saturation.
- Application of CT transient transfer characteristic in the differential protection.

On the other hand, attention should be paid to finding new protection principles that are completely different from the differential protection scheme and which no longer rely on the recognition of the inrush current and fault current to form the protection criteria. This should be a goal in constant pursuit by relay protection researchers. Three new principles totally different from the differential protection have been analysed: (i) the sequence impedance principle; (ii) the equivalent instantaneous leakage inductance principle; and (iii) the generalized instantaneous power principle. Dynamic simulation results verify the validity of the new principles.

The rapid development of electronic technology, computer technology and communication technology facilitates the development of transformer protection. Besides, with the idea of ‘main and backup protection integration’ and new principles and technology widely applied, transformer protection and operating performance will be greatly enhanced. In the near future, transformer protection will use the digital current and voltage signals from OCT (optical current transformer) and OVT (optical voltage transformer) to form the protection scheme, thus avoiding the problems in a traditional current transformer (CT) and potential transformer (PT). Transformer protection will move rapidly toward informationization, integration and intelligence.

1.4 Analysis of Electromagnetic Transients and Adaptability of Second Harmonic Restraint Based Differential Protection of a UHV Power Transformer

PSCAD/EMTDC is typical simulation software applied in various fields of power systems. In particular, it is suitable for electromagnetic transient simulations. According to the equivalent circuit of a three-winding autotransformer, a UHV autotransformer model and its internal faults model were set up by means of a UMEC (Unified Magnetic Equivalent Circuit) transformer model provided by EMTDC software. This new model takes into account both the particularity of the UHV transformer and the non-linearity of the transformer core. Based on this model, a variety of simulation tests were carried out, including energizing, inter-turn short-circuit faults, phase-to-ground short-circuit faults and phase-to-phase short-circuit faults. Finally, the current waveforms were analysed and the issues of the transformer differential protection using the second harmonic blocking scheme applied in UHV transformer protections were evaluated.
1.4.1 Modelling of the UHV Power Transformer

1.4.1.1 Basic Configuration of the UHV Power Transformer

An autotransformer is applied widely in 220 kV and higher systems due to many merits, such as low cost, high efficiency, low exciting power and so on. The tremendous capability and the high requirement for insulation lead to the huge bulk and prodigious weight of UHV transformers, as the single-phase capability of UHV transformers is up to 1000 MVA. In view of the need for convenient transport, single-phase configuration is necessary. The UHV transformer produced in China is the single-phase autotransformer [5]. The three-phase configuration is implemented with a single-phase transformer bank.

The autotransformer has a tertiary winding, namely the low voltage winding. The tertiary winding is not loaded. Instead, its functionality rests with the circulation of the third harmonic. Three phases of the tertiary winding are connected by delta-type and earthed through a low voltage reactor.

To meet the demand of electric isolation, the nonexciting voltage regulation from the neutral terminal is adopted and the voltage regulator and compensation transformer are set separately by the UHV transformer. The principle is illustrated in Figure 1.11.

SV, CV, LV, TV, EV, LE and LT represent, respectively, series winding, common winding, low voltage winding, voltage regulation winding, magnetizing winding, low voltage magnetizing winding and low voltage compensation winding. Due to this special type of coupling of windings, the short-circuit impedance of the UHV transformer is much bigger than that of the ordinary transformer.

Since the currents of all sides of the UHV transformer are the main concerns, the main transformer and the corresponding voltage-regulating compensation transformer are equivalent to a three-winding autotransformer.

1.4.1.2 The Equivalent Circuit of Three-Winding Autotransformer

No matter how the windings are arranged, the three-winding autotransformer can be studied by means of a Y-type equivalent circuit. In the following, the equivalent circuit of the UHV transformer based on the series, common and tertiary winding are modelled.

As seen in Figure 1.12, converting electrical quantities to common winding side, $\dot{U}_c'$ and $\dot{I}_c'$, are the voltage and the current respectively of the series winding. The voltage and the current of the common winding are denoted by $\dot{U}_c$, $\dot{I}_c$, $\dot{U}_q$ and $\dot{I}_q$. $\dot{U}_t'$ and $\dot{I}_t'$ represent the voltage and the current of the tertiary winding.

Similar to the ordinary three-winding transformer, the following equation can be deduced when the exciting current is ignored:

\[
\begin{align*}
\dot{U}_c' - \dot{U}_q &= \dot{I}_c' Z_c + \dot{I}_q Z_Q \\
\dot{U}_c' - \dot{U}_t' &= \dot{I}_c' Z_c + \dot{I}_t' Z_B
\end{align*}
\]

(1.26)

Figure 1.11 The principle of UHV transformer voltage regulation
where $Z'_c$ is the leakage impedance converted from the series winding, $Z_Q$ is the leakage impedance of the common winding and $Z'_B$ is the leakage impedance converted from the low voltage winding.

According to Equation (1.26), its Y-type equivalent circuit can be deduced as seen in Figure 1.13.

The parameters of the equivalent circuit can be obtained from the tests of the ordinary three-winding transformer. By this arrangement, the three-winding autotransformer can be simulated based on the ordinary three-winding transformer.

1.4.1.3 Models of the UHV Transformer for Simulation

Modelling of the UHV transformer and simulation of electromagnetic transients are both carried out by virtue of EMTDC. However, EMTDC does not provide the three-winding autotransformer models directly. According to the above analysis, and in view of the ‘electric’ relationship between the series winding and the common winding of autotransformer, two windings of the UMEC three-winding transformer model are connected to form the high voltage winding and the medium voltage winding. In this way, the UHV transformer model can be obtained.

As seen in Figure 1.14, #1 winding, #2 winding and #3 winding denote the low voltage winding, the series winding and the common winding, respectively. The validation of the equivalence is to guarantee the leakage impedances of corresponding windings are equal between the equivalent model and the original model. Significantly, the parameters of the UHV transformer should be converted to the side of the tertiary winding.

The UMEC transformer model is built primarily based on the core geometry. Unlike the classical transformer model, the magnetic coupling between windings of different phases is taken into account in the UMEC model, in addition to coupling between windings of the same phase. The piecewise technique
Electromagnetic Transient Analysis and Novel Protective Relaying Techniques

Figure 1.14 Model of the UHV transformer

is used to control the conductance of equivalent branch. The nonlinearity characteristic of the core is input directly into the model as a piecewise U–I curve, which makes full use of the interpolation algorithm for the calculation of exact instants when the state changes.

Internal faults of the transformer include inter-turn short-circuit faults, turn-to-ground faults, lead-out phase-to-phase short-circuit faults and lead-out phase-to-ground faults. The modelling of internal winding faults is the main concern of this section.

When an inter-turn fault occurs on the dual-winding transformer, the faulty turns of the faulty winding can be regarded as a tertiary winding. Based on this concept, the faulty turns of the three-winding transformer can be simulated by a fourth winding (Figure 1.15).

In Figure 1.15, #2 winding denotes the faulty turns; the fault types can be controlled by the breakers. The leakage reactance $X_2$ of #2 winding and the leakage reactance $X_3$ of #3 winding can be calculated by:

\[
\begin{align*}
X_2 + X_3 &= X_e \\
X_2/X_3 &= \left(\frac{N_2}{N_3}\right)^2
\end{align*}
\]  

(1.27)

In Equation (1.27), $X_e$ is known as the leakage reactance of the series winding. $N_2$ and $N_3$ are, respectively, the turn quantities of #2 winding and #3 winding. Practically, $N_2/N_3$ nearly is equal to the ratio of #2 winding’s rated voltage to #3 winding’s rated voltage.

1.4.2 Simulation and Analysis

Due to the nonlinearity of the transformer core, the magnetizing inrush possibly occurs when a transformer is energized, which easily leads to the mal-operation of the differential protection if no blocking
strategy is included. Therefore, identification of the inrush current is the premise of the correct operation of the differential protection. In the following, the above two models are used to simulate the energizing and internal faults of a UHV transformer. In this way, the operating behaviour of the protection can be investigated rationally.

1.4.2.1 System Model and Correlative Parameters

The system model comes from Jindongnan–Nanyang–Jingmen 1000 kV AC test and demonstration project in China, and all the parameters in the model system are from the real UHV project.

The transmission line parameters are:

Jindongnan–Nanyang: length = 363 km. Positive sequence resistance $R_1 = 0.00758 \Omega/km$, positive sequence reactance $X_1 = 0.26365 \Omega/km$, positive sequence capacitance $C_1 = 0.01397 \mu F/km$. Zero sequence resistance $R_0 = 0.15421 \Omega/km$, zero sequence reactance $X_0 = 0.7821 \Omega/km$, zero sequence capacitance $C_0 = 0.008955 \mu F/km$.

Nanyang–Jingmen: length = 291 km. Positive sequence resistance $R_1 = 0.00801 \Omega/km$, positive sequence reactance $X_1 = 0.2631 \Omega/km$, positive sequence capacitance $C_1 = 0.01383 \mu F/km$. Zero sequence resistance $R_0 = 0.1563 \Omega/km$, zero sequence reactance $X_0 = 0.8306 \Omega/km$, zero sequence capacitance $C_0 = 0.009296 \mu F/km$.

The parameters of the UHV autotransformer are:

Rated capabilities of the high voltage side, the medium voltage side and the low voltage side are 1000, 1000 and 334 MV A, respectively.

The voltage ratings of the high voltage side, the medium voltage side and the low voltage side are 1050, 525 and 110 kV, respectively.

The parameters of the short-circuit impedances (based on rated capabilities of the high voltage side) are:

The short-circuit impedance is 18% in the high–medium side, 62% in the high–low side and 40% in medium–low side.

No-load loss is 0.07%; magnetizing loss is 155 kW.

The rated capability of the high voltage reactors are:

The rated capability is 960 MV A in the Jindongnan side of Jindongnan–Nanyang transmission line and 720 MV A in Nanyang side. The rated capability is 720 MV A in Nanyang side of the Nanyang–Jingmen transmission line and 600 MV A in Jingmen side.

In view of the influences that result from the energizing transient of the transmission lines and high voltage reactors, the energizing position is at the high voltage side of UHV transformer at Jingmen side.

The configuration of the system model is shown in Figure 1.16.

As seen in Figure 1.16, the UHV source is connected to the high voltage side of the UHV transformer via UHV transmission lines. The medium voltage side is linked with an equivalent load, while low voltage winding is connected in delta-type and is grounded through a reactor and a capacitor for compensation.

Actually, the source of the UHV project is provided by the medium voltage side of the UHV transformer at Jindongnan. It is no harm to replace Jindongnan by an equivalent source since the emphasis rests with the energizing at Jingmen. The reactors are modelled by the parallel inductances and the capacitors are modelled by capacitances. The remnant flux is modelled by the DC source, which is put on the high voltage side of the UHV transformer.
1.4.2.2 Simulation and Analysis of Energizing

Energizing simulations are carried out in terms of diverse initial angles and remnant fluxes. A scenario of typical inrush waveforms of three phases is shown in Figure 1.17. As seen, the harmonics of the inrush is more abundant than the transformer’s in EHV and lower level systems, leading to the more abnormal waveforms.

The UHV transformer adopts Y/Δ-11 type. Therefore, the concern focuses on the differential current, which determines whether the differential protection can operate correctly or not. The differential current is the summation of three-side incoming currents. Therefore, the phase and magnitude compensation should be carried out instead of summation directly. Namely, if the incoming currents of the high, medium and low voltage sides of phase A are $\dot{I}_{ah}$, $\dot{I}_{am}$ and $\dot{I}_{al}$, and the incoming currents of the high, medium and low voltage sides of phase B are $\dot{I}_{bh}$, $\dot{I}_{bm}$ and $\dot{I}_{bl}$, in view of the phase compensation and magnitude compensation, the differential current of phase A should be

$$\left(\dot{I}_{ah} - \dot{I}_{bh}\right) + \frac{525\sqrt{3}}{1050\sqrt{3}} \left(\dot{I}_{am} - \dot{I}_{bm}\right) + \frac{100}{1050\sqrt{3}} \dot{I}_{al}.$$

Because the transformer is energized at the high voltage side, there are no currents in the other two sides. Therefore, the differential current of phase A is $(\dot{I}_{ah} - \dot{I}_{bh})$ exactly. Table 1.3 shows the harmonic ratios of the three-phase differential currents in various energizing conditions.

![Figure 1.16](image1.png)

**Figure 1.16** Jindongnan–Nanyang–Jingmen system model

![Figure 1.17](image2.png)

**Figure 1.17** Magnetic inrush currents in typical energizing, initial angle of phase A is $0^\circ$; remnant flux densities of the three phases are all 0
Table 1.3  Harmonic analysis of inrush currents

<table>
<thead>
<tr>
<th>Remnant flux density</th>
<th>Initial angle of phase A (°)</th>
<th>Second harmonic ratio (%)</th>
<th>Phase A</th>
<th>Phase B</th>
<th>Phase C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Phase A: 0B_m</td>
<td>0</td>
<td></td>
<td>30.4</td>
<td>40.4</td>
<td>15.1</td>
</tr>
<tr>
<td>Phase B: 0B_m</td>
<td>30</td>
<td></td>
<td>31.8</td>
<td>22.6</td>
<td>14.8</td>
</tr>
<tr>
<td>Phase C: 0B_m</td>
<td>60</td>
<td></td>
<td>37.0</td>
<td>23.7</td>
<td>34.3</td>
</tr>
<tr>
<td>Phase A: 0.7B_m</td>
<td>0</td>
<td></td>
<td>16.0</td>
<td>18.9</td>
<td>10.1</td>
</tr>
<tr>
<td>Phase B: 0.5B_m</td>
<td>30</td>
<td></td>
<td>17.0</td>
<td>15.4</td>
<td>1.9</td>
</tr>
<tr>
<td>Phase C: 0.5B_m</td>
<td>60</td>
<td></td>
<td>30.3</td>
<td>15.0</td>
<td>3.7</td>
</tr>
<tr>
<td>Phase A: 0.9B_m</td>
<td>0</td>
<td></td>
<td>12.8</td>
<td>17.7</td>
<td>4.0</td>
</tr>
<tr>
<td>Phase B: 0B_m</td>
<td>30</td>
<td></td>
<td>9.8</td>
<td>6.9</td>
<td>6.1</td>
</tr>
<tr>
<td>Phase C: 0.9B_m</td>
<td>60</td>
<td></td>
<td>17.0</td>
<td>17.0</td>
<td>7.8</td>
</tr>
</tbody>
</table>

According to Table 1.3, when the initial angle of phase A is 30°, the harmonic ratio of one phase will be under 15%, even if no remnant flux exists. If the remnant flux is taken into account, the harmonic ratio of phase C will fall below 1.9%, as shown in fifth row of Table 1.3. This indicates that it is unrealistic to only adjust the harmonic restraint ratio to avoid the mal-operation of the differential protection. The mal-operation above cannot be avoided unless the following blocking strategy is adopted, that is, set the threshold of harmonic restraint ratio as 15% and implement the blocking while the second harmonic ratio of the differential current of any phase exceeds the threshold. Furthermore, when the remnant fluxes of the three phases are 0.9, 0 and 0.9B_m and the initial angle of phase A is 30°, the second harmonic ratios of the three-phase differential currents are all under 10%, of which the corresponding waveforms are shown in Figure 1.18. In this case, even the above strict countermeasure will not allow the protection to survive.

In this scenario, mal-operation is unavoidable even though the above-mentioned blocking strategy is adopted and the harmonic restraint ratio is regulated to 15%.

The higher order harmonics, especially the odd harmonic of the inrushes of the UHV transformer, are more abundant than in an ordinary transformer. This possibly has some impact on the methods used to identify inrush by means of waveform characteristic.

Figure 1.18  Magnetic inrushes leading to the mal-operation of differential protection
It is impossible to simulate all the conditions involving the diverse initial angles, remnant flux densities and different operation states of systems to validate the existing schemes for differential protection. However, the simulation results presented in this section at least suggest that the second harmonic characteristic of the inrush of the UHV transformer is weaker than that in EHV and lower voltage systems. This scenario should be paid attention to when commissioning the differential protection of the UHV transformer.

### 1.4.2.3 Simulation and Analysis of Internal Faults

The simulations of inter-turn short-circuit faults, turn-to-ground fault of various short-circuit turns ratios have been carried out. For simplicity, all the faulty phases are designated phase A.

Moreover, several lead-out short-circuit faults are simulated by means of the FAULTS module provided by EMTDC, including phase A to ground faults, phase A–B short-circuit faults and phase A–B to ground faults.

Several phase current waveforms of phase A in different fault conditions are shown in Figure 1.19. As seen, for inter-turn short-circuit faults or for phase to ground faults, more turns are short-circuited the smaller the primary current is. When the lead-out fault occurs, the fault current is high and distorted. Accordingly, in order to investigate the operation of the differential protection, the three-side incoming currents of the transformer should be phase compensated to form the differential current. The second harmonics of differential currents in manifold fault conditions were analysed; some results are given in Table 1.4, the data window length is one cycle. Due to the phase compensation, phase B has no differential current when the fault occurred in phase A.

### Table 1.4 Harmonic analysis of fault currents

(a) Internal winding short-circuit fault

<table>
<thead>
<tr>
<th>Fault type</th>
<th>Fault turns ratio (%)</th>
<th>Second harmonic ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Phase A</td>
</tr>
<tr>
<td>Inter-turn short-circuit</td>
<td>2</td>
<td>22.6</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>8.0</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>3.7</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>2.7</td>
</tr>
<tr>
<td>Turn-to-ground</td>
<td>2</td>
<td>4.6</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>3.8</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>3.6</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>3.1</td>
</tr>
</tbody>
</table>

(b) Lead-out short-circuit faults

<table>
<thead>
<tr>
<th>Fault type</th>
<th>Second harmonic ratio (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Phase A</td>
</tr>
<tr>
<td>Phase A to ground</td>
<td>3.3</td>
</tr>
<tr>
<td>Phase A–Phase B</td>
<td>3.7</td>
</tr>
<tr>
<td>Phase A–B to ground</td>
<td>3.1</td>
</tr>
</tbody>
</table>
According to Table 1.4, due to the effect of the distributed capacitance of the UHV transmission line and the particularity of the UHV transformer, abundant harmonics exist within the fault currents. However, except for a 2% inter-turn fault, the ratios of the second harmonic of the differential currents in the case of diversified faults are under 15%. The most adverse scenario is a 5% inter-turn fault, of which the second harmonic is 8%. Combined with the analysis of inrush currents, the mal-operation probability may be evidently reduced if the second harmonic restraint ratio declines properly, for example, declining to 10%. Meanwhile, it will not influence the operating speed of the differential protection in a mass of fault conditions.

The case of a 2% inter-turn fault is an exception. In this case, the second harmonic of the differential current of the faulty phase is 22.6%, which exceeds the conventional setting value of second harmonic restraint ratio. The differential current waveform in this scenario is shown in Figure 1.20.

Furthermore, the change of the second harmonic content in this condition is investigated, referring to Figure 1.21.
As seen, the second harmonic of the differential current declines rapidly. The second harmonic ratio is 22.6% after the first post-fault cycle elapses. After that, it decreases to 19% at 21 ms, to 15.3% at 22 ms, to 12.4% at 23 ms, to 10% at 25 ms and to 7.4% at 26 ms. The time delay is only 6 ms even if the threshold of restraint ratio is set to be 10%.

According to the simulation results, the second harmonic based blocking scheme can, on the whole, distinguish between inrush and fault current. The protection can be reliably blocked during the energizing of the UHV transformer if the second harmonic restraint ratio is set below 10%. However, it may lead to some time delay in the response of the differential protection to some scenarios of internal faults.
In this sense, the discrimination between the inrush and the fault current of the UHV transformer is still valuable.

A great many beneficial works for identifying the inrush from fault current have been reported [6–9]. Their adaptability to the UHV transformer base can be assessed on the models of energizing and internal fault of the UHV transformer proposed in this section and chose a satisfactory one. Accordingly, the operational level of the differential protection of the UHV transformer can be improved further.

In summary, based on the benchmark model of the transformer provided by EMTDC, the energizing and internal fault models of UHV transformer are established in this section in terms of autotransformer mode. The corresponding electromagnetic transient simulations in a UHV environment are carried out, and reasonable preconditions for investigating the operating performance of the UHV transformer protection are offered. These models are especially suitable for evaluating the applicability of the existing main protection systems of transformers to the UHV test and demonstration project in China. The emphasis of this section rests with evaluating the operation reliability of the differential protection based on second harmonic blocking. It is proven with the simulation results that the harmonic characteristic of the inrush of the UHV transformer is weaker than that of the transformer in EHV and lower voltage grade systems. The second harmonic ratios of three-phase differential currents may be all under 10% in some extreme conditions. On the other hand, in the fault conditions, the second harmonic ratios of differential currents all exceed 10%, except some light inter-turn faults. In terms of comprehensive analysis of the inrush and fault current obtained from the simulation tests, the differential protection with the second harmonic blocking scheme still has redundancy when applied to UHV transformer protection. As for the light inter-turn fault, although the second harmonic ratio is higher than 15% by the end of the first post-fault cycle, this ratio decreases to 15% below at 23 ms and goes below 10% at 26 ms. Therefore, the time delay of the protection is not serious in the case of internal faults.

1.5 Study on Comparisons among Some Waveform Symmetry Principle Based Transformer Differential Protection

Recently, a type of criteria based on so-called ‘symmetry waveform’, which identify the inrush by comparing the first half cycle and the second half cycle of a signal, are proposed. Because this theory makes full use of the shape, size and changing ratio of the waveform, it is worth being studied further. Some references identified three criteria based on the symmetrical waveform from different aspects and made some simulations and dynamic simulation tests to validate them. However, the analysis of this is not comprehensive because of the diversity of the inrushes and fault currents. Therefore, the performance of symmetrical waveform based methods for identifying the inrushes and fault currents was investigated. Useful conclusions were gained after the test and comparison of the three criteria.

1.5.1 The Comparison and Analysis of Several Kinds of Symmetrical Waveform Theories

1.5.1.1 The Theory of Integral-Type Symmetrical Waveform and its Analysis

The main idea of the theory using the integral-type symmetrical waveform is shown in Figure 1.22. Divide the sampling signals A B C of a whole cycle into two half cycles AB and BC with the same length, B'C' can be obtained by flipping the second half cycle BC with symmetry in the X-axis. Then quadrilateral ABCD can be formed using DE that is translated forward by B'C' and the first half cycle AB. Denote the area of this quadrilateral as $S$, the area of straight ladder as $S_{ti}$, the area overlapped by AB and the X-axis $S_{+}$, and the area overlapped by BC and X-axis $S$. Also, denote the factor of symmetry waveform as:

$$K_{sym} = \frac{|S - S_{+}|}{\max(S_{+}, S_{-})}$$  (1.28)
The periodic component of signals AB and DE can be offset with each other. In this case, $S_i = S_j$ can be obtained for the ideal periodic sinusoidal signal containing only the DC component. $S_i, S_j$ are equal to zeros for a pure sine signal. $K_{sym}$ is equal to zero under the above premise. For the inrush, the value of $K_{sym}$ fluctuates around a positive value, of which the maximum value is 1.4 and the minimum value is larger than zero. The fault and the inrush can be identified using this method [10]. Fuzzy recognition is used for practical implementations. The Trip Counter is designed using different ways of counting due to different $K_{sym}$. When the accumulated value of the Trip Counter is larger than the threshold, the inrush is identified and this phase is then blocked. This scheme is denoted criterion 1.

The speed of the protection output is faster than conventional methods in the case of a low percentage of the fault current harmonic component. However, long time delay will occur in the case of serious distortion of fault currents. Figure 1.23 shows the waveform comparison between fault current and three-phase inrushes recorded by the dynamic simulation laboratory of Huazhong University of Science and Technology.

The fault is set as the B–C short-circuit occurring on the transformer with load and long-distance line connected. The sample rate is 12 points per cycle. The waveform obtained from the disturbance recorder includes two cycles before the fault and five cycles after the fault. From this figure it can be seen that the distortion is serious because of the influence caused by the capacitive current of the long line and the bad characteristic of CT.

To make the figure easy to understand, Figure 1.24 only shows how $K_{sym}$ changes with the fault current and the inrush in C-phase. Figure 1.25 shows how the Trip Counter changes with the fault current and inrush. The X-axis represents the time duration of post-fault. The bold solid lines represent how $K_{sym}$ or Trip Counter change, and the normal solid lines represent how $K_{sym}$ or Trip Counter changes.

The rules of changing of the fault current $K_{sym}$ and the inrush are similar to each other in five cycles; meanwhile, the counting of the trip counter of the inrush in C phase is always smaller than that of the fault current; it is difficult to identify the inrush from the fault current. Therefore, it is not appropriate to use criterion 1 in the case of serious distortion on the fault current waveform. Further study needs to be done to make this scheme adapt to the complex contingencies occurring in the high voltage system.

1.5.2 The Theory of Waveform Symmetry of Derivatives of Current and Its Analysis

A waveform symmetry method is proposed based on comparing the symmetry of the first half waveform and the second half waveform of the current derivative. The main idea is that, in a time window of one
cycle plus one point, the derivatives of differential current with one cycle time window are obtained using the forward differentiation operation. Then, the derivative series of the first half cycle are compared with that of the second half cycle. Denote the value of one point in first half cycle of derivative current as $I'_{i}$ and denote the value of the second half as $I'_{i+180}$. If the value satisfies Equation (1.29), the waveform is
regarded as symmetrical. Otherwise, the waveform is asymmetrical.

\[
\frac{|I'_i + I'_{i+180^\circ}|}{|I'_i - I'_{i+180^\circ}|} \leq K_{sym} \tag{1.29}
\]

It declares that in the whole half cycle (180°), the angle satisfying the inrush characteristic could reach as much as 60°, while that of the fault current could reach 150°.

Therefore, this scheme needs two setting values. One is the symmetrical factor \(K_{sym}\), the other is symmetrical range \(K_{angle}\). If the sampling rate is \(N\) points per cycle, the symmetrical range can be expressed as

\[
K_{m} = K_{angle} \times N / 360 \tag{1.30}
\]

Denote Equations (1.29) and (1.30) criteria 2, where \(K_{m}\) is relative, with the sampling points satisfying the symmetrical condition (1.29) in one cycle. For example, if the angle satisfying the symmetry condition at most is \(K_{angle} = 60^\circ\) and there are 12 sample points per cycle, \(K_{m} = N/6 = 2\). For the inrush current waveform, there are at least two points satisfying the symmetry condition.

The above analysis focuses on the primary side waveform of the inrush under a certain value of \(K_{sym}\). If the setting value is set on the basis of secondary waveform of inrush current, \(K_{sym}\) should be reduced to guarantee the symmetry constraints of 60°. The symmetry range will be reduced under 150° with the reduced \(K_{sym}\). Under some serious conditions, the time delay may be very long before the setting value of 60° is reached. This situation is analysed here.

Figure 1.26 shows the three phase magnetizing inrushes from the secondary side of CTs. The wiring type of \(Y_0/\Delta-11\) is applied in the transformer. The iron is Type-96 material, that is, the nonlinear inductance model with hysteresis loops. The saturation magnetic density is \(B_s = 1.15B_m\) and residual magnetism of each phase \(B_{ra} = 0.9B_m, B_{rb} = B_{rc} = -0.9B_m\). The inception angle is 30°. The B–H curve of the CT adopts the characteristic of a tangent, the sampling rate is 120 points per cycle.

The symmetry factor can be calculated after deriving the inrush waveform. For the scenario in Figure 1.26, the symmetry degrees of the first half and the second half waveform of the three phase
inrushes are all quite high. The number of points of the three-phase inrush current satisfying constrains of symmetry are calculated and shown in Table 1.5.

As shown in the table, in order to reach the requirements of inrush, which only have $60^\circ$ symmetric range, the value of symmetric coefficient $K_{sym}$ should not be too high. When $K$ is equal to 0.15, the phase C secondary inrush has reached 21($63^\circ$). Evidently, in order to ensure that the symmetric range is not greater than $60^\circ$, the value of symmetric coefficient $K_{sym}$ can only be taken as 0.15 if taking the secondary transforming into account. At this time, take the fault current in Figure 1.23 to analyse the tripping speed of this criterion. Choose $K_m = 2$, $K_{sym} = 0.15$, the fault current $K_m$ is less than or equal to two in five cycles after the fault occurrence. In this case, the protection cannot trip. Increase $K_{sym}$ gradually until $K_{sym}$ is equal to 0.2. By this means, the fault current cannot lead to $K_m = 3 > 2$ until 93.3 ms after the fault occurrence. In this case, the protection will trip with a very long time delay. Thus, under low sampling rate conditions it is found that, to ensure that the mal-trip due to inrush is reliably blocked, there is no obvious advantage for this scheme compared with the second harmonic restraint principle. In the case of high harmonic content within the fault current, the protection would also trip with a long time delay.

Take $K_{sym}$ as the basic symmetry coefficient and $K_m * K_{sym}$ as global setting value $K'_{sym}$. Improving $K'_{sym}$ means that mal-operation may occur due to inrush, and reducing $K'_{sym}$ makes the delay longer when the fault occurs.
There exists another implementation of this scheme, that is, let \( S_+ = \frac{N}{2} \sum_{i=1}^{N/2} |I_i + I_{i+N/2}| - S_- \), and therefore \( K_{sym} = S_+ / S_- \). When \( K_{sym} > K_{symset} \) it will be judged as the inrush, otherwise it will be judged as the fault. The greater the value of \( K_{sym} \) the higher the degree of asymmetry. This scheme is named criterion 3. The transformer protection adopting criterion 3 is produced by Nanzi and has been commissioned. For the true waveform, \( S_+ = 0 \), and \( S_- \) is a positive real number. For the magnetizing inrush, no matter whether there is dead angle or not, \( S \) is always nonzero as long as the first half wave and the second half wave do not strictly satisfy the symmetry conditions (\( S = S_+ = 0 \) in Section 1.5.1). This scheme is similar to the percentage differential principle to some extent, among which \( S_+ \) can be regarded as the differential quantity and \( S_- \) can be regarded as the restraint quantity. Furthermore, calculating the three-phase inrush symmetric coefficients in Figure 1.25 applying based on criterion 3, the values are 0.35, 0.53 and 0.21, respectively. In order to compare with criterion 2, taking \( K_{symset} = 0.21 \), the sensitivity is analysed based on the waveform in Figure 1.23.

At the beginning of the fault, \( K_{sym} \) is much greater than \( K_{symset} \). Along with the attenuation of the harmonic with the differential current, \( K_{sym} \) continues to reduce. At the time of 98.3 ms post-fault, \( K_{sym} = 0.20 \), the protection trips while criterion 2 fails to trip. Obviously, any comparison should be conducted on the same basis. As shown in the above analysis, based on the waveform in Figure 1.26, and 60° as the maximum symmetry of the inrush (corresponding \( K = 0.15 \)), in the case of Figure 1.23, criterion 1 fails to trip within five cycles after the fault occurrence. Only in the case of \( K \) increasing to 0.2, can criterion 1 operate with five cycles time delay. To facilitate the following comparison, criterion 1 will take the condition of \( K_{sym} = 0.20 \) in the following discussion. For the other criteria which take the condition of \( K_{sym} = 0.20 \), the waveform symmetry coefficient must be adjusted correspondingly. Assume that the original waveform symmetry coefficient being set entirely based on Figure 1.22 is \( K'_{symset} \), and the protection trips when waveform symmetry coefficient is less than the setting, the new setting value \( K_{symset} \) should be:

\[
K_{symset} = K'_{symset} \times \frac{0.20}{0.15}
\]

If the protection trips when the waveform symmetry coefficient is less than the setting, the new setting value \( K_{symset} \) should be:

\[
K_{symset} = K'_{symset} \times \frac{0.15}{0.20}
\]

After performing the above adjustments, the comparison between every new criterion and criterion 1 are taken under the same condition that the \( K_{sym} \) of the criterion is 0.2. Here, the above approach is used to maintain the same reliable discrimination margin for all criteria.

Therefore, increasing the \( K_{symset} \) of criterion 2 to 0.21 × 0.20 = 0.28, \( K_{sym} \) drops to 0.207 and the protection trips in 83.3 ms after the fault occurred. In this case the operating time of criterion 2 is 93.3 ms. Therefore, under the premise of the same sampling rate, criterion 3 is slightly better than criterion 2.

### 1.5.3 Principle and Analysis of the Waveform Correlation Method

The basic idea of the waveform analysis method to identify the inrush is to divide the waveform of one cycle data window into two parts using appropriate methods and compare the correlation of these two parts to identify the inrush and the fault current. The key problem of the wave correlation algorithm is how to determine these two waveforms. A so-called maximum area method is illustrated in Figure 1.27. One cycle sampling signal is extended to two periods. Intercept the half cycle signal point by point and calculate the projection area of this waveform on the time axis. Denote the sampling period as \( N \) points in one period, thus giving \( N \) values. The corresponding starting point of maximum area is taken as the start of waveform comparison \( (t = 5 \text{ ms}) \) in Figure 1.27. One period sampling signal is intercepted from
this point, as shown in Figure 1.27 using major gridlines. The second half wave is reversed, that is, $-y$. The first half wave is $x$, then $-y$ and $x$ are compared using the modified waveform factor as given by Equation (1.33):

$$J = \frac{\text{Cov}(X,Y)}{\sigma^2(X)}$$ (1.33)

where $\text{Cov}(X,Y)$ is the covariance coefficient of $X$ and $Y$, $\sigma^2(X)$ is the variance of $x$. Then, for the fault current that only contains the DC component, it is clear that waveform of the first half wave is completely consistent with that of the negative second half wave, that is, they are completely correlative ($J = 1$). Reorganize the waveform of the inrush according to the above principle, its correlation between the first half wave and the second half wave becomes worse. Hereby, the inrush can be identified. The waveform correlation method is called criterion 4. Denote $J_{set}$ as a fixed value. When the result is $J < J_{set}$, the current is regarded as inrush, otherwise it is fault current.

Correspondingly, the three-phase inrushes in Figure 1.26 are calculated using criterion 4, and the waveform factors are $J_{a-b} = 0.6513$, $J_{b-c} = 0.2107$ and $J_{c-a} = 0.8038$, respectively. Set the modified waveform factor as $J_{zd} = 0.80$ due to generally adopting phase-separating blocking, protection cannot trip until 95 ms after fault occurrence (4.75 periods). Comparing criterion 2 with criterion 3 in the same reliability margin, the setting value will be decreased to 0.6. Meanwhile, the fault will be tripped with a time delay of 60 ms, which is better than criteria 2 and 3, and the tripping speed is also faster than the second harmonic restraint criterion that has 15% restraint ratio (81.6 ms).

1.5.4 Analysis of Reliability and Sensitivity of Several Criteria

It can be seen from the analysis above that for criterion 3 the waveform is more symmetrical when the symmetrical coefficient is smaller. For criteria 2 and 4 the scenario is different. To investigate the maximum degree of the inrush to reach symmetrical condition and analyse the reliability of the criterion quantitatively during the practical energizing operation, sufficient switching-on experiments should be made. The symmetrical coefficient is calculated according to the recorded data. The minimum symmetrical coefficient should be used when criterion 3 is investigated, and the maximum waveform (symmetrical) coefficient should be calculated when criteria 2 and 4 are studied. In addition, the basic symmetrical coefficient $K_{sym}$ should be determined firstly when calculating the symmetrical coefficient $K_{sym}^*$ in criterion 2. The inrush is still considered in the maximum symmetrical range of 60° (two sampling points in terms of 600 Hz sampling rate). It increased from 0.2 to $K_{sym}$ gradually. When the inrush increases to 0.3, there
Table 1.6  The minimum ratios of second harmonic to fundamental in the case of some
inrushes recorded by digital device and the corresponding waveform coefficients with criteria 2, 3 and 4 under the most adverse judging conditions.

<table>
<thead>
<tr>
<th>Inrush number</th>
<th>( \text{Min} (I_2/I_1) ) (%)</th>
<th>Criterion 2 ( (J_{\text{max}}) )</th>
<th>Criterion 3 ( (J_{\text{min}}) )</th>
<th>Criterion 4 ( (J_{\text{max}}) )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>47</td>
<td>0.58</td>
<td>0.65</td>
<td>0.5</td>
</tr>
<tr>
<td>2</td>
<td>56</td>
<td>0.58</td>
<td>0.54</td>
<td>0.5</td>
</tr>
<tr>
<td>3</td>
<td>46</td>
<td>0.58</td>
<td>0.65</td>
<td>0.5</td>
</tr>
<tr>
<td>4</td>
<td>43</td>
<td>0.58</td>
<td>0.55</td>
<td>0.55</td>
</tr>
<tr>
<td>5</td>
<td>58</td>
<td>0.58</td>
<td>0.58</td>
<td>0.55</td>
</tr>
<tr>
<td>6</td>
<td>39*</td>
<td>0.58</td>
<td>0.64</td>
<td>0.41</td>
</tr>
<tr>
<td>7</td>
<td>42</td>
<td>0.58</td>
<td>0.66</td>
<td>0.44</td>
</tr>
<tr>
<td>8</td>
<td>42</td>
<td>0.58</td>
<td>0.62</td>
<td>0.51</td>
</tr>
<tr>
<td>9</td>
<td>50</td>
<td>0.58</td>
<td>0.57</td>
<td>0.48</td>
</tr>
<tr>
<td>10</td>
<td>49</td>
<td>0.58</td>
<td>0.53</td>
<td>0.55</td>
</tr>
</tbody>
</table>

are three sampling points of the inrush (Table 1.6) satisfying the symmetrical condition. Therefore, the largest basic symmetric coefficient that can be adopted as 0.29 in criterion 2, and the corresponding symmetric coefficient \( K_{\text{sym}} \) is 0.58.

In Table 1.6, faults 1–4 are the transformer energizing without long line, faults 5–9 are the transformer energizing with long line. Fault 10 is the inrush current caused by the voltage recovery when the external fault is removed.

The minimum or maximum symmetric coefficient of each inrush is analysed during energizing in five cycles. To compare with the second harmonic restrained method, the proportion of second harmonic in three-phase inrushes and the fundamental harmonics are calculated point-by-point. The maximum value in three phases is taken as an element of the second harmonic restrained ratio sequence. Then the percentage of the second harmonic ratio for five cycles is calculated and the minimum value taken as the minimum second harmonic ratio of actual inrush. The analysis of 10 classical inrush groups is listed in Table 1.6.

It can be seen from the table that the minimum value of second harmonic ratio is 39% and the normal setting value is 15%. To ensure the same reliable discrimination margin, the setting value in criterion 2 should be the maximum value in the table and it should be divided by the coefficient 39/15. The setting value in criterion 3 should be the minimum value in the table and it should be divided by the coefficient 39/15. The setting value in criterion 4 should be the maximum value in the table and it should be multiplied by the coefficient 39/15. Then the operation times of criteria 2–4 are calculated respectively when the comparability to the second harmonic restrained method is guaranteed. The setting value for criterion 2 is 0.23, 0.204 for criterion 3 and 1.43 for criterion 4. The waveform coefficient is 1 when the waveform is completely correlated, the setting value in criterion can be taken as 0.8 as in the inrush current shown in Figure 1.26.

The classic faults of the transformer in Table 1.7 are analysed based on the above settings. The non-operation times of the second harmonic restrained method and criteria 2–4 are listed in Table 1.7.

Cases 1–18 in Table 1.7 are classic transformer faults and cases 19–27 are transformer energizing faults. Cases 1–4 represent phase B to ground fault. The operation condition is with load and long line, with load but without long line, without load but with long line, without load and long line, respectively. The following are studied by considering four cases as one group. Among them cases 5–8 are BC inter-phase short-circuit on the high voltage side; cases 9–12 are AB inter-phase short-circuit on the low voltage side; 13–16 are 4.38% inter-turn short-circuit, 17–18 are 2.18% inter-turn short-circuit. In faults 19–27, two situations are combined as one group. Cases 19 and 20 are B phase short-circuit...
Table 1.7  Nonoperation times in milliseconds for the second harmonic restraint scheme and for criteria 2, 3 and 4 under typical fault conditions

<table>
<thead>
<tr>
<th>Fault number</th>
<th>$I_2/I_1$ (ms)</th>
<th>Criterion 2 (ms)</th>
<th>Criterion 3 (ms)</th>
<th>Criterion 4 (ms)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>81.6</td>
<td>NOP</td>
<td>NOP</td>
<td>95</td>
</tr>
<tr>
<td>2</td>
<td>60</td>
<td>93.3</td>
<td>75</td>
<td>68.3</td>
</tr>
<tr>
<td>3</td>
<td>58.3</td>
<td>83.3</td>
<td>61.6</td>
<td>46.6</td>
</tr>
<tr>
<td>4</td>
<td>18.3</td>
<td>31.6</td>
<td>18.3</td>
<td>18.3</td>
</tr>
<tr>
<td>5</td>
<td>93.3</td>
<td>NOP</td>
<td>NOP</td>
<td>48.3</td>
</tr>
<tr>
<td>6</td>
<td>63.3</td>
<td>98.3</td>
<td>75</td>
<td>43.3</td>
</tr>
<tr>
<td>7</td>
<td>78.3</td>
<td>NOP</td>
<td>95</td>
<td>83.3</td>
</tr>
<tr>
<td>8</td>
<td>60</td>
<td>NOP</td>
<td>75</td>
<td>40</td>
</tr>
<tr>
<td>9</td>
<td>58.3</td>
<td>NOP</td>
<td>75</td>
<td>38.3</td>
</tr>
<tr>
<td>10</td>
<td>20</td>
<td>70</td>
<td>35</td>
<td>28.3</td>
</tr>
<tr>
<td>11</td>
<td>73</td>
<td>NOP</td>
<td>90</td>
<td>40*</td>
</tr>
<tr>
<td>12</td>
<td>58.3</td>
<td>NOP</td>
<td>70</td>
<td>36.6</td>
</tr>
<tr>
<td>13</td>
<td>31.6</td>
<td>33.3</td>
<td>31.6</td>
<td>30</td>
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<td>14</td>
<td>31.6</td>
<td>33.3</td>
<td>31.6</td>
<td>31.6</td>
</tr>
<tr>
<td>15</td>
<td>20</td>
<td>21.6</td>
<td>21.6</td>
<td>18.3</td>
</tr>
<tr>
<td>16</td>
<td>25</td>
<td>26.6</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>17</td>
<td>20</td>
<td>18.3</td>
<td>20</td>
<td>21.6</td>
</tr>
<tr>
<td>18</td>
<td>26.6</td>
<td>28.3</td>
<td>26.6</td>
<td>23.3</td>
</tr>
<tr>
<td>19</td>
<td>NOP</td>
<td>NOP</td>
<td>NOP</td>
<td>81.6</td>
</tr>
<tr>
<td>20</td>
<td>NOP</td>
<td>NOP</td>
<td>75</td>
<td>60</td>
</tr>
<tr>
<td>21</td>
<td>NOP</td>
<td>NOP</td>
<td>NOP</td>
<td>50</td>
</tr>
<tr>
<td>22</td>
<td>NOP</td>
<td>95</td>
<td>75</td>
<td>40</td>
</tr>
<tr>
<td>23</td>
<td>NOP</td>
<td>NOP</td>
<td>76.6</td>
<td>25*</td>
</tr>
<tr>
<td>24</td>
<td>NOP</td>
<td>96.6</td>
<td>71.6</td>
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<td>25</td>
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<td>31.6</td>
<td>26.6</td>
<td>25</td>
</tr>
<tr>
<td>26</td>
<td>NOP</td>
<td>45</td>
<td>26.6</td>
<td>25</td>
</tr>
<tr>
<td>27</td>
<td>NOP</td>
<td>26.6</td>
<td>20</td>
<td>23.3</td>
</tr>
</tbody>
</table>

NOP: nonoperation, that is, fail-to-trip.

accompanied by transformer energizing; cases 21 and 22 are inter-phase short-circuit between phase B and phase C on the high voltage side accompanied by transformer energizing; cases 23 and 24 are inter-phase short-circuit between phase A and phase B on the low voltage side accompanied by transformer energizing; cases 25 and 26 are 4.38% inter-turn short-circuit accompanied by transformer energizing; case 27 is 2.18% inter-turn short-circuit without long line accompanied by transformer energizing.

Figure 1.28 illustrates the tripping times of 27 kinds of classic fault calculated by the second harmonic restrained method and by criteria 2–4. The abscissa shows fault number and the ordinate shows the tripping time. The threshold of protection fail-to-trip is set as 300 ms.

It can be seen by combining Table 1.7 and Figure 1.28 that:

1. The operation speeds are the same in the case of single-phase short-circuit and inter-turn short-circuit (1–4, 13–18).
2. The operation speed from slow to fast is: criterion 2 $\rightarrow$ criterion 3 $\rightarrow$ criterion 4 in the case of inter-phase short-circuit faults except the inter-phase short-circuit between phase B and phase C without load but with long line. And the performance of criterion 4 is the best.
Electromagnetic Transient Analysis and Novel Protective Relaying Techniques

Figure 1.28 Non-operation time of scheme 2 to scheme 4 with the same reliability

3. The performance of criterion 4 is the best when the fault accompanied by transformer energizing occurs, it always can operate correctly. These always exist the scenarios of fail-to-trip for other criteria.

4. The operation speed is not ideal when the fault waveform distortion becomes bigger in the three criteria (t > 90 ms).

In summary, the three criteria by waveform symmetry principle for transformer differential protection, the reliability and sensitivity of the criteria are analysed. The Alternative Transients Program (ATP) is used to simulate the inrush scenario, which is critical to validate the waveform symmetry based methods so that the reliability of this type of method can be tested. The sensitivity is verified by the distorted fault current waveform resulting from the dynamic simulation experiment. It can be seen from the comparison that the sensitivity of criterion 4 is higher than that of the other two criteria when those criteria have the same reliability margin under the circumstances of transformer energizing and external fault removal. The faults can be tripped correctly even when the fault waveform distorts greatly or is accompanied by the transformer energizing. Criterion 2 and criterion 3 may fail to trip for some fault cases. Criterion 4 is the best among all waveform symmetry based methods. However, when the waveform is distorted seriously, the operation speed of criterion 4 is still slow. To achieve a better effect in large-scale transformer protection, existing methods should be further optimized.

1.6 Summary

With large capacity transformers being put into operation continuously, the demand for high reliability, rapidity and sensibility are on the increase. It is imperative to consummate transformer differential protection and bring forward novel transformer main protection schemes. In this section, various problems in current differential protection principles and inrush current blocking schemes have been studied and discussed. By comparative research, the development route of the transformer main protection technology is given.

References

Principles of Transformer Differential Protection and Existing Problem Analysis


