Substation Testing and Commissioning: Power Transformer Through Fault Test

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Abstract

This paper reviews the advantage of performing transformer through-fault test in substation testing and commissioning prior to the actual energization in addition of theory of testing and numerical procedure. This test allows the engineer and relay technicians to validate all the CTs and PTs secondaries, transformer winding configuration, protective relays and wiring correctness and circuit. The value and benefit of performing this test is also shown in real world project.

Index Terms

Transformer, Through-Fault, Substation, Commission and Testing.

I. Introduction

Substation commissioning and testing is a critical task prior to substation energization to ensure all equipment will function safely in the intended manner. Medium and large power transformers in distribution or transmission power system are often protected by differential relay because of its high sensitivity and fast operation. The principal and design of transformer differential relaying has been covered and described in many literature and manuals and it is not the scope of this paper [1]–[4]. After design and installation of transformer differential relay, it is essential to prove and validate its circuit prior to substation energization. An incorrect wiring of the differential relaying will cause false operation or no operation of protective relays during normal or fault event. Several incidents have been reported by the U.S power utility system regarding improper wiring and circuit of CTs in power transformer protective relaying which has resulted in transformer protection mis-operations with short and long-term impact and consequences [2]. It is still a common practice in the U.S. utility system to defeat the transformer differential relay function before connecting it to the load and performing the in-service test to verify its circuit after the actual substation energization. It is clear that validating all protection circuits and discovering all potential errors prior to substation energization, without disabling the relay function, is highly desirable. As such, in this paper, a detailed procedure of the through-fault test for power transformer differential circuit prior to substation energization using the practical examples is covered. This practical commissioning test was developed decades ago and the authors are simply presenting the theory and procedure of how the test performs in the substation.

The reminder of the paper is organized as follows: Section II reviews the through-fault test application and advantages. The test and numerical calculation procedure is presented in section III. Section IV discusses performance and results of through-fault test with real world example and section V concludes the paper.

II. Preliminary

In the power transformer protection, through-fault is the system fault that are external to the transformer protection zone. It is a well known concept that the zone of the protection in transformer differential relay will be defined by the location of the CTs secondaries. Through-fault test apply the balance three phase voltage, equal voltage magnitude and displaced 120 degree among phases, on one side of the transformer or circuit breaker. Since the circuit is balance, transformer positive sequence impedance will be in series with positive sequence voltage and current of test source and circuit will complete its current loop by shorting and grounding all bushings outside the differential relay zone of protection. Through-fault test will prove the CTs polarity are correct and the expected direction of secondary current flow is correct for a given direction of primary current flow. It will also simply confirm the transformer CTs ratio by proving that the ratio, as installed, is as specified and listed in the drawing and transformer's nameplate, and if taps are available, that they also have the correct ratio and have been wired to the correct terminals. Furthermore, it is a useful test for verifying power transformer winding connections and phase displacement corresponding to its vector group on the nameplate in the field. Depending on phasing connection, this phase shift may be either plus or minus 30 degree from primary to secondary for positive sequence voltages and currents. It will also confirm protective relaying wiring correctness. Potential transformers secondaries can also be checked during this test.

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It should be noted that all other protective relays in transformer protection design scheme such as 50/51 can also be tested during through-fault testing.

III. Test Procedure and Numerical Calculation

Prior to the test, transformer differential protection zone should be identified based on the relay functional drawing. Expected test current value and phasor diagram should be computed before running the through-fault test. The test source voltage, transformer and CTs winding connections, transformer impedance, transformer power capacity and its tap position under the test, system phase rotation, phase-to-bushing connections, and CTs and PTs ratios are required for the calculation procedure. It should be noted that the size and output voltage of temporary generator required in the filed as a test source voltage will be determined after calculating the current flow through the circuit. Based on the microprocessor protective relays manual, a minimum secondary current of 0.25 amps is required to pass the pickup and accuracy range of the digital relays. Hence, sometimes transformer size and its impedance make it difficult to choose the temporary generator used for through-fault test in the field to push the minimum required current. Practically, the common temporary generator output voltage used in the field is at a maximum of 480-500 VAC with 125 KVA.

A. Calculation Procedure

Test source voltage will be in series with positive sequence impedance of the transformer; therefore, eq. 1 is for calculating the $p.u.$ value of the injecting current by test source [5], [6],

$$I_{G_{p.u.}} = \frac{V_{G_{p.u.}}}{Z_{xfmr_{p.u.}}}, \tag{1}$$

where $I_{G_{p.u.}}$, $V_{G_{p.u.}}$, and $Z_{xfmr_{p.u.}}$ are $p.u.$ the values of the test source current, test source voltage, and transformer impedance respectively.

For calculating the $V_{G_{p.u.}}$, simply use the p.u. equation of,

$$V_{G_{p.u.}} = \frac{V_G}{V_{Base}} \tag{2}$$

,

where V_G is the output voltage of the test source voltage and V_{Base} is the voltage of the transformer side (usually the low side) the test source is connected to.

Now, by applying the three phase power equation, we can calculate the transformer low and high side $Base$ currents,

$$I_{H_{Base}} = \frac{MVA}{\sqrt{3}V_{H_{xfmr}}} \tag{3}$$

$$I_{L_{Base}} = \frac{MVA}{\sqrt{3}V_{L_{xfmr}}}, \tag{4}$$

where $V_{H_{xfmr}}$, and $V_{L_{xfmr}}$ are the high and low side of the transformer voltage in KV and MVA is the power capacity of the transformer on the tap under the test.

Finally, by applying eq. 5 and 6, we can calculate the current flow through the transformer primary and secondary side respectively,

$$I_{H_{xfmr}} = I_{G_{p.u.}} \times I_{H_{Base}}, \tag{5}$$

$$I_{L_{xfmr}} = I_{G_{p.u.}} \times I_{L_{Base}}. \tag{6}$$

The magnitude of the current in the CTs secondaries can be calculated by dividing current magnitudes calculated in eq. 5 and 6 to CTs ratios.

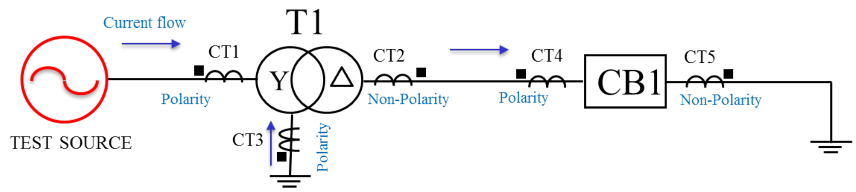


Fig. 1. Simplified Single-Line Diagram.

TABLE I
CURRENT MAGNITUDE AND PHASE ANGLE OF CTS FROM FIG. 1

$Current$	$PhaseA$	$PhaseB$	$PhaseC$
I_G	$I_G\measuredangle 270$	$I_G\measuredangle 150$	$I_{G_{p.u.}}\measuredangle 30$
I_{CT1}	$\frac{I_G}{CT_1R}\measuredangle 270$	$\frac{I_G}{CT_1R}\measuredangle 150$	$\frac{I_G}{CT_1R}\measuredangle 30$
I_{CT2}	$\frac{I_G}{CT_2R}\measuredangle 120$	$\frac{I_G}{CT_2R}\measuredangle 360$	$\frac{I_G}{CT_2R}\measuredangle 240$
I_{CT3}	$0\measuredangle 0$		
I_{CT4}	$\frac{I_G}{CT_4R}\measuredangle 300$	$\frac{I_G}{CT_4R}\measuredangle 180$	$\frac{I_G}{CT_4R}\measuredangle 60$
I_{CT5}	$\frac{I_G}{CT_5R}\measuredangle 120$	$\frac{I_G}{CT_5R}\measuredangle 360$	$\frac{I_G}{CT_5R}\measuredangle 240$

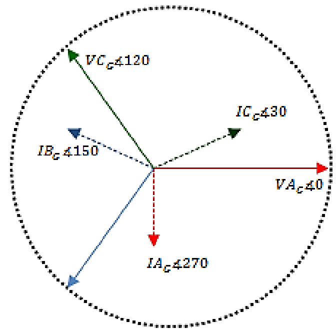
For measuring the phase angle in the CT secondary, a known phase voltage (usually phase A with zero degree phase angle of test source) should be chosen as a reference. The inductive nature of power transformer in addition to phase displacement between transformer's winding has to be considered for CTs secondaries phase angle measurement. Fig. 1 shows a basic substation one-line diagram. For simplicity, lets just assume that transformer differential relay zone is from $CT1$ to $CT2$. Test source is connected to the low side of the transformer and as shown, bushing on the line side of the circuit breaker has been shorted and grounded. Phase A current out of test source lags 90 degrees the reference voltage, $V_A\measuredangle 0$, and measures $I_a\measuredangle 270$. Looking to Fig. 1, this current will enter to the polarity side of $CT1$ in primary side of power transformer and will have same phase angle with lower current magnitude depending to $CT1$ ratio. On the secondary side of the transformer, phase A current enters to non-polarity side of $CT2$ and it should measure $I_A\measuredangle 120$ in Wye connected configuration CT secondary seen in microprocessor differential relay (transformer 30 degrees phase shift plus 180 degrees is experienced from the mirrored polarity of both winding CTs). It is essential to know how the phase angle meter display has been programmed i.e. if it is in leading or lagging operation state. Reading above is for the meter programmed in leading operation state which means the value displayed is the number of degrees by which the current leads the voltage. If the meter has been programmed in lagging operation state, the meter will display $I_a\measuredangle 90$ and $I_A\measuredangle 300$ for $CT1$ and $CT2$ respectively.

Fig. 2 shows the expected phasor diagarm of voltage and current for standard Delta-Wye transformer differential circuit. By selecting phase A voltage, $V_A\measuredangle 0$, as a reference, phasor diagram of voltage and current of test source connected to Wye side should be expected as Fig. 2(a). Remember that the power transformer is considered as an inductive load and current lags voltage by 90 degree. In practical power transformer there is always resistive component so there will be $3-5\%$ difference from the expected value. Fig. 2(b) shows the phase angle relationship between CTs secondaries on both sides of the transformer, $CT1$ and $CT2$. Again, it should be noted that the angles are measured by using temporary generator phase A voltage as a reference. The magnitude of phasors shown in the Fig. 2 is arbitrary and purpose is just showing the phase angle relationship. Table I summarized the expected values for CTs magnitude and phase angle corresponding to Fig. 1 with phase angle meter in leading operation state.

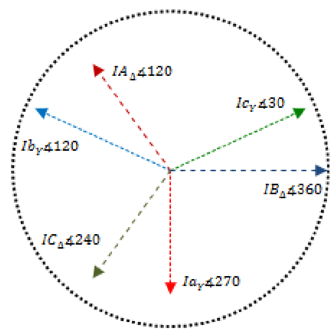
B. Testing Procedure

Here are the steps should be taken in the field for performing the through-fault test:

1) Prior to performing the through-fault test, it is important that all safety procedures regarding the switching, locking, and tagging be observed and formalized to avoid the protection engineers and technicians from being exposed to substation equipment that has not been properly de-energized.
2) Location of connecting the test source in one side and shorting and grounding of bushing on the other side of protection zone based on the relaying functional diagram and substation layout has to be identified.
3) Primary conductors and phasing needs to be visually proven and identified to have a correct phasing prior to the test.
4) Temporary generator phase rotation needs to be verified before the test.



(a) Phase angle relationship between test source voltage and current in primary side of Transformer



(b) Phase angle relationship between current in $CT1$ and $CT2$ seen by protective relay

Fig. 2. Expected Phasor Diagram of Fig. 1.

5) Generator current magnitudes need to be known and a phase reference needs to be established in order to analyze the reading. Current can be measured using a clamp-on ammeter and compared with the first CT calculation in calculation sheet. Phase reference is chosen to prove correct phasing and polarity of all CT circuits to be tested and it can be phase A to ground voltage of the temporary generator. All the phase angle readings during the test will be based on the chosen reference. Therefore, engineer or technician needs to have extended test leads to go from reference point to all measuring points.

IV. Practical Example Case Study

A real world project with expected and measured values under the test is covered and illustrated in this section to show the effectiveness of the testing method.

A. *Solar Project*

Fig. 3 shows the modified single line diagram of a 50 MW solar project. The GSU transformer nameplate information were as follows: 3 phase, 24/32/40MVA, 115/34.5KV Delta-Wye two winding configuration. The impedance of the transformer under 24MVA was measured as $\%7.33$ and transformer was under 115 KV tap. The transformer differential relay zone of protection starts from CTs on the line side of breakers 52-1 and 52-2, $CT4$ ($600/5$ tap) and $CT3$ ($600/5$ tap) and goes to line side of transformer breaker, 52-21, $CT1$ ($300/5$ tap). CT1 and CT2 are 115KV line side CTs of main circuit breaker, CT3 and CT4 are 34.5KV line side CTs of feeder breakers.

Through-fault test was performed at solar substation by connecting a 3-phase 500V generator to the line side disconnects of each 34.5 KV feeder and applying shorts on the line side disconnects of the 115 KV circuit breaker. Prior to the test, expected values for current calculated as follows by applying equations (1)-(6):

$$V_{G_{p.u.}} = \frac{500}{34.5KV} = 0.0144 \tag{7}$$

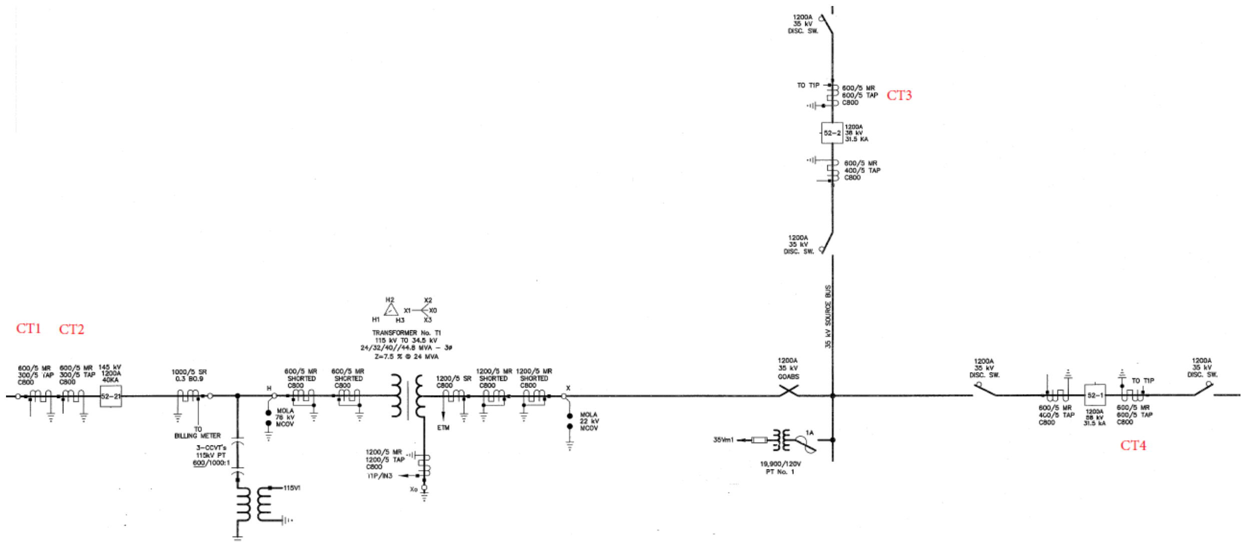


Fig. 3. Modified single line diagram of solar project.

$$I_{G_{p.u.}} = \frac{0.0144}{0.0733} = 0.197 \tag{8}$$

$$I_{H_{Base}} = \frac{24MVA}{\sqrt{3}115KV} = 120.49A \tag{9}$$

$$I_{L_{Base}} = \frac{24MVA}{\sqrt{3}34.5KV} = 401.64A \tag{10}$$

$$I_{H_{xfmr}} = 0.197 \times 120.49 = 23.73A \tag{11}$$

$$I_{L_{xfmr}} = 0.197 \times 401.64 = 79.41A. \tag{12}$$

Applying $CT4$ and $CT3$ ratio of $600/5$, current magnitude in the secondary is 0.66A. For the PT located in $34.5KV$ bus, $PT1$, with $19900/120$ ratio, the expected voltage magnitude in PT secondary can be calculated as

$$V_{PT} = \frac{288}{165.8} = 1.74V \tag{13}$$

After calculating expected values, voltage and current readings were taken on each CT and PT circuit to validate CT and PT wiring and relay settings. Table II shows the expected values vs. measured values of CTs circuits. The phase angle meter was in lagging operating state. During final walk through before the testing started, it was discovered that several CT shorting screws were not removed and CT tap ratios did not match the single line. After these issues were corrected, the testing started. During the test it was discovered that A and C phase wiring on all CT and PT circuits were rolled and CT connections shown on the single line were connected to the wrong relay windings. As shown in the table II, the expected value of phase A current was $0.66\measuredangle 90$ but the measured value was $0.66\measuredangle 327$ which was the expected value of C phase. It was also discovered that the differential relay CT connection compensation settings were set wrong. Winding 2 CT, $CT4$ and $CT3$, connection compensation setting was set as 1 where it should have been 11 to compensate 30 degrees phase shifting from low to high side, meaning Wye side leading Delta side by 30 degree.

TABLE II
MAGNITUDE AND PHASE ANGLE OF CURRENTS OF SOLAR FARM PROJECT- EXPECTED V.S. MEASURED

CTS	Expected Value			Measured Value		
	Aϕ	Bϕ	Cϕ	Aϕ	Bϕ	Cϕ
CT1	$0.397\measuredangle 300$	$0.397\measuredangle 60$	$0.397\measuredangle 180$	$0.385\measuredangle 177$	$0.388\measuredangle 58$	$0.388\measuredangle 297$
CT2	$0.397\measuredangle 300$	$0.397\measuredangle 60$	$0.397\measuredangle 180$	$0.383\measuredangle 176$	$0.388\measuredangle 58$	$0.389\measuredangle 297$
CT3	$0.662\measuredangle 90$	$0.662\measuredangle 210$	$0.662\measuredangle 330$	$0.66\measuredangle 328$	$0.65\measuredangle 208$	$0.67\measuredangle 88$
CT4	$0.662\measuredangle 90$	$0.662\measuredangle 210$	$0.662\measuredangle 330$	$0.66\measuredangle 327$	$0.65\measuredangle 207$	$0.67\measuredangle 87$

After this discovery, wiring for CTs and PTs were corrected and tested again to confirm the correctness of the circuit.

V. Conclusion

In this paper, the theory, application, and advantages of transformer through-fault test in substation commissioning was covered. Through-fault test employs a temporary generator as a three phase test source to inject three phase balance currents into the power transformer windings and its CTs; therefore, allowing the engineer and relay technicians to measure current and voltage magnitude and phase angle in the CTs and PTs secondary and protective relays. The test will check the integrity and correctness of the circuit and will discover incorrect wiring, polarity, and setting prior to actual energization. This gives enough time to relay technicians and engineers to troubleshoot the circuit and take necessary corrective actions.

VI. Acknowledgment

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VII. References

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