Analysis of the Unexpected Operations at a 345kV National Grid Substation Associated with Capacitor Bank Switching-off Operation

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Introduction:

In modern society, electricity is indispensible to our daily life. A fault in the power system could result in power quality issues and blackouts to a large area. Therefore, power system faults should be isolated by protection in a timely, effective and selective manner. Any over-trips of non- faulted sections shall also be avoided. When over-trips occur, they should be investigated to prevent from re-occurring. Correct and rapid fault clearance and power outage minimization are of great concern to utility companies and regional Independent System Transmission Operators.

Shunt capacitor units are applied in the power system for power factor correction. With improved power factor, the better power quality, less line & transformer losses and lower maximum demand will be achieved. Typically, the on and off switching of capacitor banks is frequent at substations. Capacitor bank switching should not affect other protection and control systems at the station. This paper reviews an over-trip of a 345kV transmission line during a capacitor bank switching-off operation and presents the root causes of the misoperation with the help of digital fault recorder (DFR) as well as logs from Energy Management System (EMS). Mitigation measures to avoid misoperation are introduced to the readers.

System Overview:

NS substation, a 345kV bulk power station, is located in the Albany, New York and it is one of the key stations in the capital region. NS station is configured with two straight 345kV and 115kV buses. Two 345kV to 115kV step down transformers, transformer 1 & 2, are the electrical link between 345kV & 115kV buses. At the same voltage level, two tie breakers run between each straight bus.

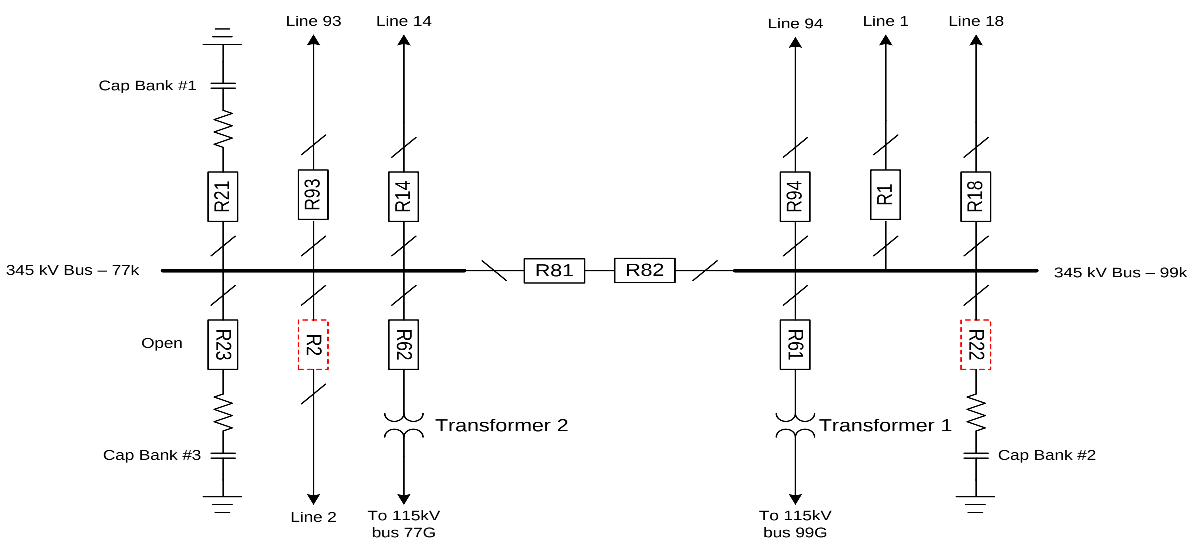

Figure 1: System one line of 345kV system at NS substation

Transmission lines are tied to buses via the corresponding breakers. Line 2, 14 & 93 are connected to 345kV bus 77k while line 1, 18, 94 are tied to bus 99k. Capacitor banks, #1, 2 & 3, are provided on the 345kV bus system for reactive power and voltage control. Cap banks 1 & 3 are connected to 345kV bus 77k and Cap bank 2 is connected to 345kV bus 99k. Most of the time, only one cap bank is in-service on each bus.

All the primary equipment at the station is provided with separate and redundant protection systems which are independent. Dual high-speed pilot protection schemes are provided for 345kV transmission lines. The capacitor bank is also provided with dual protections with voltage differential protection (87V) on System 1 and backup phase & neutral overcurrent protections on System 2. Breaker failure protection is provided for all 345kV breakers at the station. A breaker failure direct transfer trip (BF-DTT) will be initiated for line breakers following the operation of a breaker failure relay.

Event & Incident Summary:

At 21:12:37 PM of April 17th of 2019, when the control center remotely sent a trip command to open 345kV breaker R22 of cap bank 2, 345kV breaker R2 for line 2 (NS – A Station) was unexpectedly tripped coincident with the opening of breaker R22. During this event, a direct transfer trip target from line 2 Direct Transfer Trip (DTT) relay was received. The remote station, A, of line 2 confirmed there was no trip & fault at their end and no DTT was ever sent over to NS terminal.

The sequence of event (SOE) from EMS is below:

4/17/2019 21:12:37	NS	345 BKR R22	BKR	Open-Command
4/17/2019 21:12:37	NS	345 BKR R22	BKR	Open
4/17/2019 21:12:37	NS	345 BKR R2	BKR	Open

It was confirmed that both primary and secondary protection systems of line 2 at NS were not triggered and no relay record was available. However, line 2 DTT relay recorded a record shown figure 2 below.

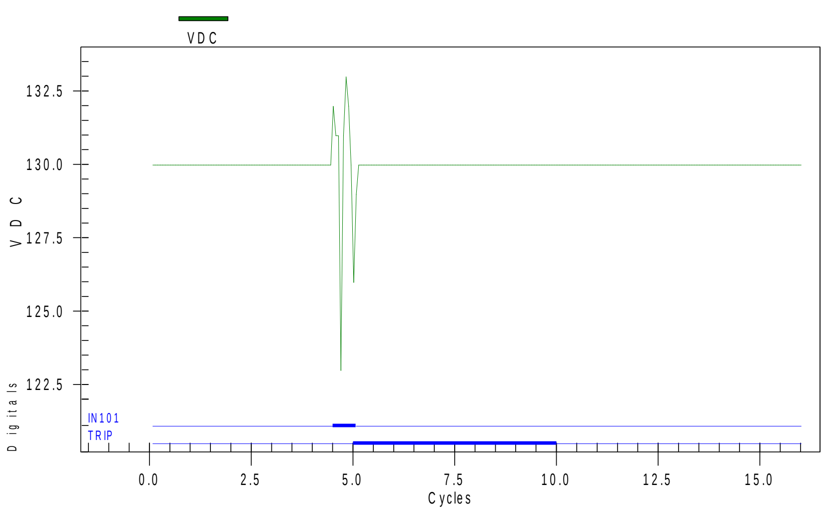

Figure 2, LN2 DTT relay record

As the relay trace shows, digital input IN101 was momentarily asserted during cap bank 2 switching-off operation. This input was initiated from the output contact of communication terminal equipment and used for transfer trip, and then the transfer trip signal was sent to the line 2 breaker. Further inspections confirmed both the local and remote communication equipment never had an event logged during this trip. The remote station also confirmed everything was normal during R2 breaker trip at NS station.

Now the question arises; why the DTT relay received a momentary transfer trip signal via digital input IN101 while no real DTT signal was transmitted from the communication equipment? In addition to the momentary assertion of digital input IN101, the voltage level of 125V DC for the relay got some fluctuations which happened simultaneously with the cap bank 2 switching and receipt of the false DTT signal. Since the sampling rate of the DTT relay is relatively low (18 points per cycle), it is difficult to figure out the real maximum magnitude and the pattern of DC fluctuations. Because the secondary control cables are provided for DC battery and digital input IN101 of the relay, those control cable must have experienced some noise signals during cap bank 2 switching. Now it is the time to visit the DFR record to see the switching process of cap bank 2.

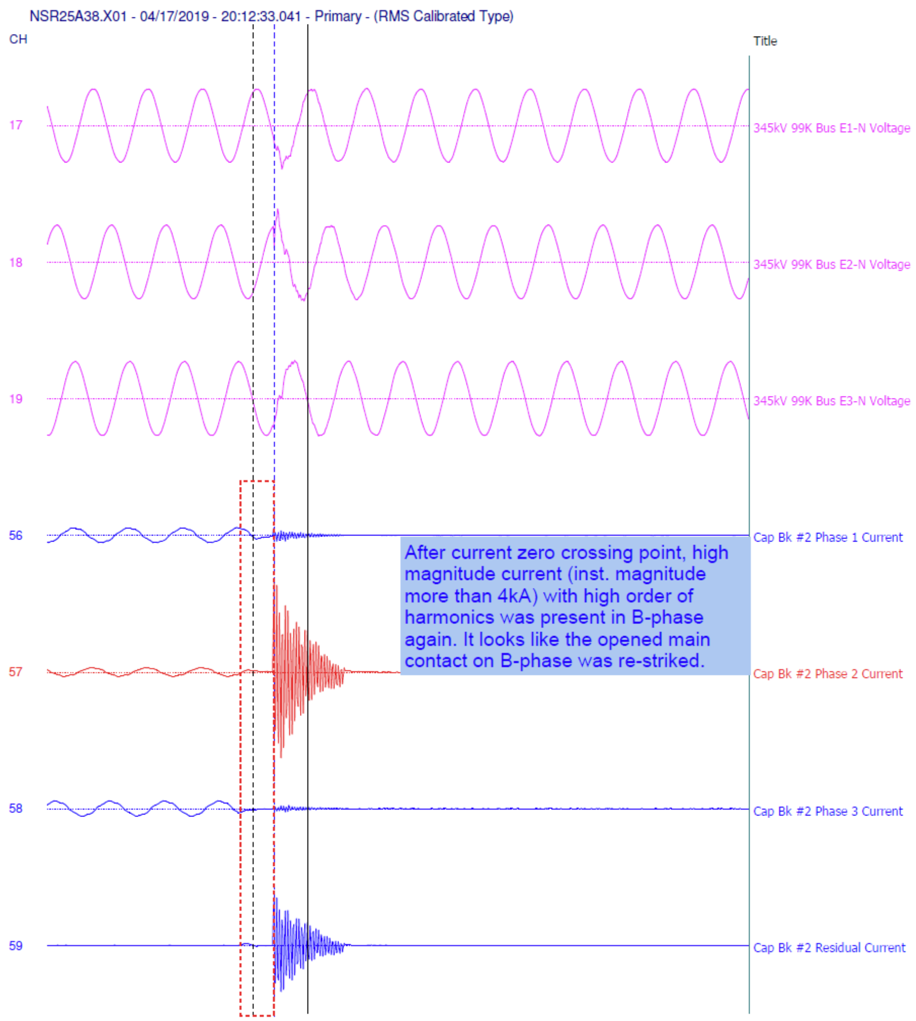

Figure 3: DFR record showing 345kV bus voltages and R22 current at New Scotland

After receiving the manual trip command from control center, the main contacts of breaker R22 for capacitor bank 2 started to depart. However, B-phase breaker re-stroke after the first current zero crossing point while the arc of other two phase breakers was successfully extinguished. The longitudinal transient voltage must have been developed across the main contact of B-phase breaker when the breaker was trying to interrupt capacitive current from capacitor bank. The transient voltage was higher than the dielectric strength between the fixed and movable main contact of the breaker in its "open" status. After the re-ignition inside of B-phase breaker, approximately 4kA peak harmonic current lasted for another cycle before the current finally extinguished. Once the energy stored in the capacitor dissipated, the transient voltage across the breaker main contact/blade was dropped to the source side voltage.

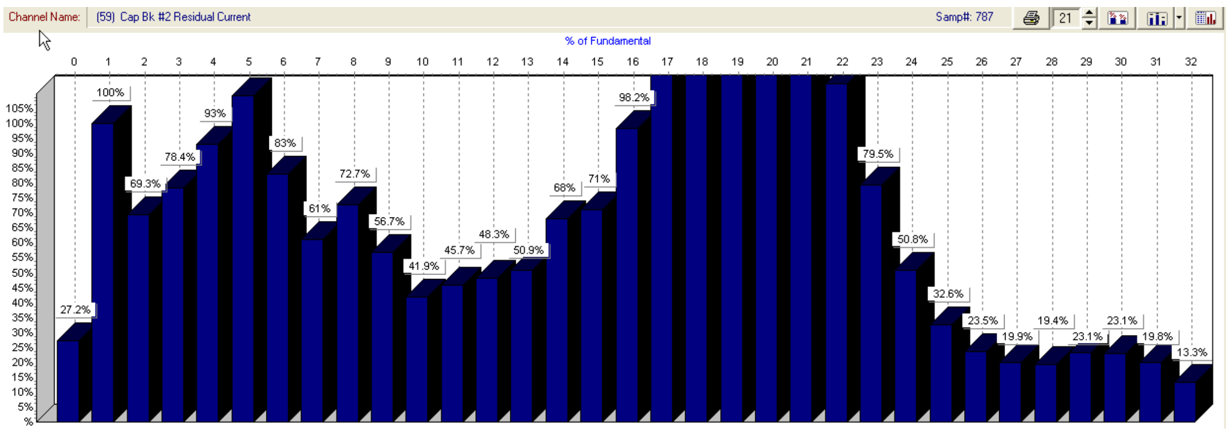

Figure 4: Harmonic components table of cap bank 2 residual current during switching

Per above analysis, huge amount of harmonics in both odd and even order were present in the neutral current of cap bank 2. During switching, the total harmonic distortion (THD) was 2770%. In other words, approximately 4000A of current with high component of harmonics were injected into the grounding grid of NS substation during the cap bank switching off operation. This resulted in electromagnetic interference on DTT circuit of line 2 at the station.

How line 2 DTT relay was affected by capacitor bank 2 switching transients? In Figure 2, 4kA peak current with high harmonic contents was injected into the grounding grid of the substation; which typically consists of a combination of vertically driven ground rods, horizontally buried interconnecting grounding cables, connections to the metal parts of underground foundations, connections from the buried grid to metallic parts of surface structures and equipment, and connections to grounded system neutrals. The typical station grounding grid topology is shown in Figure 5.

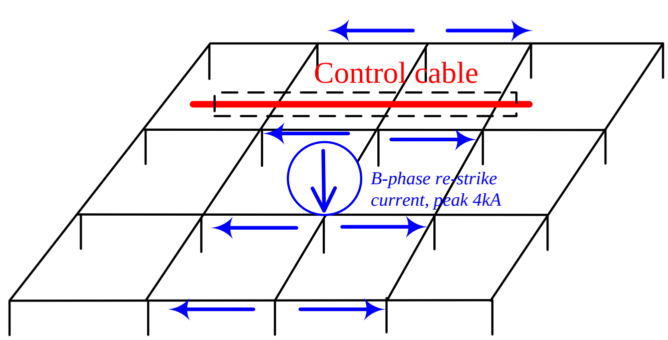

Figure 5: The typical layout of a substation grounding grid

The control cables for a station secondary system are installed either in the cable trenches or conduits which are above the grounding grid. If the control cable and grounding grid conductors are not orthogonal in the space, a mutual inductance will exist between the conductors, thus the current flowing in the grounding grid will produce the induced voltage in the secondary circuits. When the residual current from capacitor bank switching was injected into substation grounding grid, the induced voltage would appear in the control cable circuit. Relay record in Figure 2 confirmed that the significant voltages were coupled into control cables by the transient current from station ground grid.

The similar line DTT trip occurred in the past during cap bank switching-on operation due to malfunction of synchronous control unit (SCU). The paper for such event has been published in Georgia Tech 2018 Fault and Disturbance Analysis Conference. Since then, control cables at NS station have been upgraded to shielded type with grounding on both end shield layers, which would reduce the interference from high frequency noise signals on control cable conductors via magnetic coupling. As the injected current into the grounding grid was so large (4kA) during the switching, the significant induced voltage was still present on the control cable conductors even with grounded shield layers.

<u>Breaker interrupting process:</u>

As the movable and fixed main contacts of the breaker departs, the effective resistance between the contacts increases with time. Thus the current in the circuit decreases to a certain value unable to sustain the arc. For AC circuit and the resistive nature of the arc, the current would intend to be in phase with the source voltage and finally the arc extinguishes at zero crossing point. To achieve successful current interruption, the adequate electrical dielectric strength must be established rapidly across the breaker contacts after current zero crossing to minimize the chance of restrike.

The transient recovery voltage, TRV, of the breaker is defined as the voltage which appears across the terminals of a pole of a circuit breaker during the interruption process. TRV is voltage difference from the source side to load side across the breaker blade; it can be considered in two successive time intervals. The first interval is for transient voltage with high frequency oscillations and followed by the second power frequency voltage (60Hz). The breaking operation is successful if the circuit breaker is able to withstand the TRV. However, many factors would affect TRV of the breaker, such as the nature of gas or oil, the gas pressure, the number of the opening operations, the contacts shapes, type of the circuit (resistive, inductive or capacitive), etc. The typical SF6 breaker interrupter and TRV across the contacts are shown Figure 6.

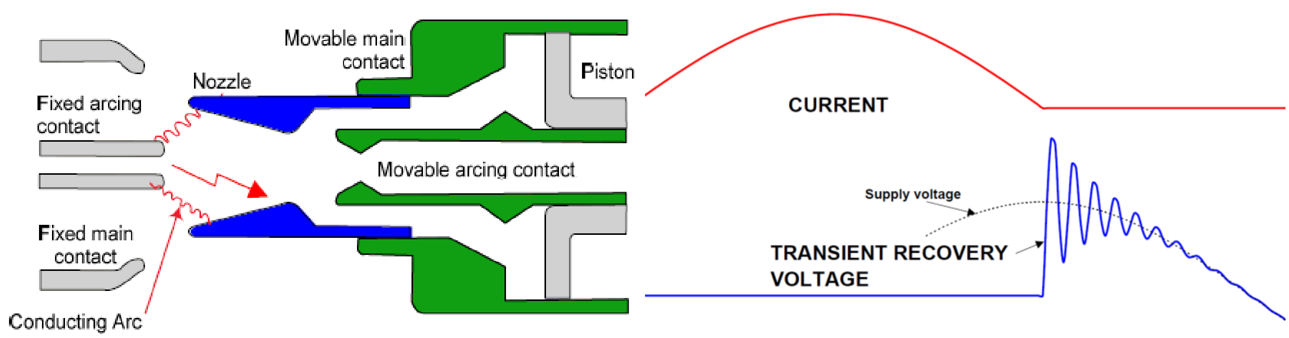

Figure 6: Typical SF6 breaker interrupter (Left) and TRV across contacts (Right)

The severity of a TRV depends on both the magnitude and the rate of rise of the voltage across the opening circuit breaker poles. Based on ANSI Standard C37.09, the allowable TRV values for grounded shunt capacitor is 2.0 times P.U.

Per DFR records, B-phase breaker of cap bank 2 experienced restrike during the opening operation. In other words, the voltage across the breaker movable and fixed main contacts exceeded the breaker rated transient recovery voltage (TRV).

Controlled switching is a technology which coordinates the instant of opening or closing of a circuit with a specific target point on an associated voltage or current waveform. Currently, the cap bank breaker R2 is controlled by a synchronous control unit (SCU) for switch-on operation only, which would close the breaker at voltage zero crossing moment during the energization. However, the breaker opening is random and not controlled. If the breaker opening is controlled and the transient voltage across the breaker blade is below the rated TRV of the breaker, the restrike can be eliminated.

The strategy of controlled switching:

In power systems, switching operations are frequent and inevitable. Every switching operation, open or close, potentially introduces a disturbance into the steady-state of the power system. These disturbances are called switching transients and can last for a fair amount of time. The switching transients, which may have magnitudes of several per unit, can affect both primary and secondary systems in the substation. Synchronous switching is a method of reducing switching transients by controlling the exact timing for a breaker to make & break a circuit, and thereby minimize the switching transients in the first place.

In order to assume synchronous switching, the main feature of an SCU consists of introducing a suitable delay between the instant it receives an input command for operating the switchgear and the instant it actually starts energizing the switchgear coils. Switching controller uses the PT signals from the busbar as the reference voltage and uses the CT of the capacitor as feedback signals. The typical application of the switching controller is shown in Figure 7.

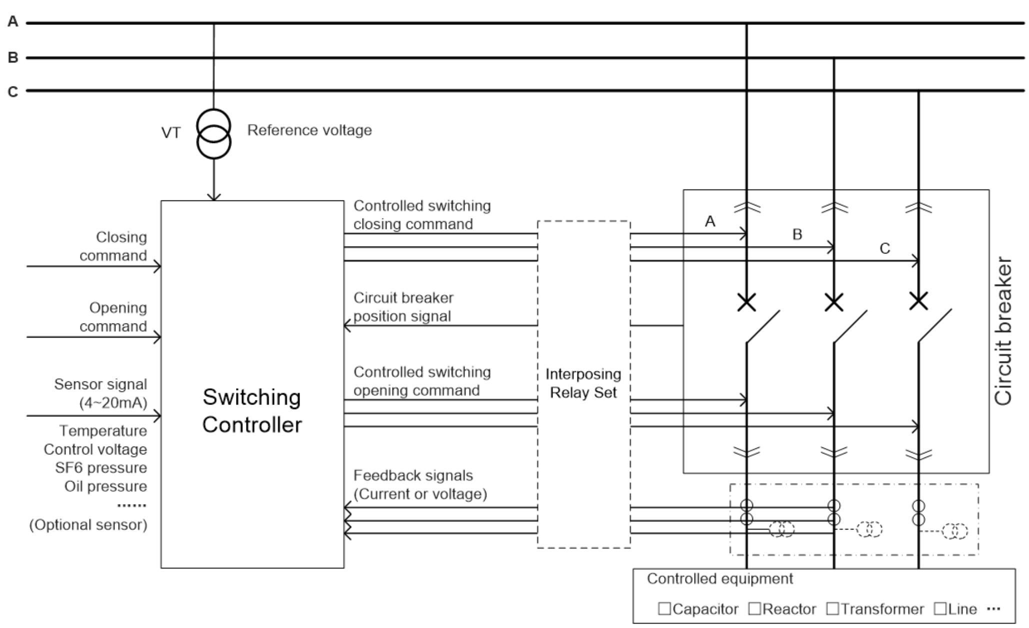

Figure 7: The typical application of switching controller

1) The best target point to energize a capacitor is when the phase voltage reaches the value of the steady voltage across the capacitor; generally, we choose the voltage zero-crossing point. Once the SCU received the closing command, it will compute the suitable delay to be introduced between the voltage zero-crossing point and the start of coil energization, then the SCU energizes the closing coil of the circuit breaker at the optimum instant. The controlled closing process is shown in Figure 8.

It should be noted that, RDDS (Rate of Decay of Dielectric Strength), which is the rate that the dielectric strength across the CB closing contacts, is decreasing as the contacts come closer. The current may start flowing slightly before the contacts mechanically touch.

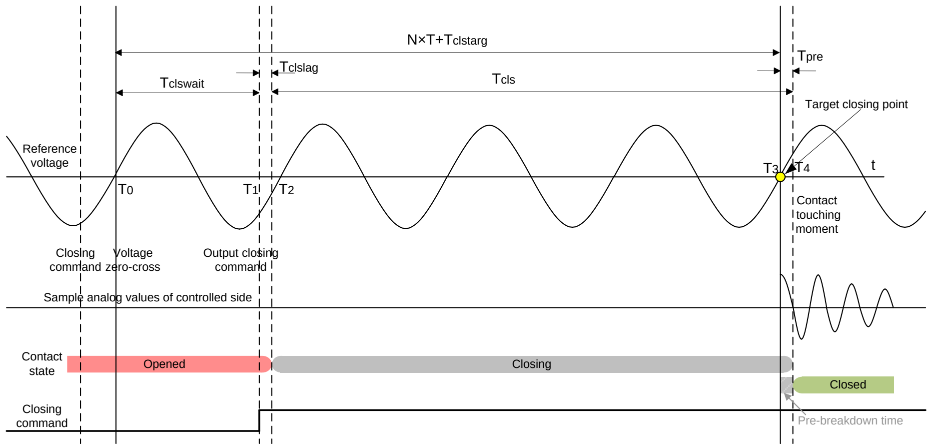

Figure 8: Controlled closing process

Where:

$T_{clswait} = N \times T + T_{clstarg} - T_{cls} - T_{clslag} + T_{pre}$
N is an integer;
$T_{clswait}$ is the waiting time of the controlled closing operation which considers the pre-breakdown time;
T is the period time of the reference voltage;
$T_{clstarg}$ is the time which is calculated from the target closing phase angle;
T_{cls} is the inherent closing time of the circuit breaker;
T_{clslag} is the lag time of the closing circuit;
T_{pre} is the pre-breakdown time.

2) For the capacitive interruption case, the current leads the voltage by 90-degree. At the interruption current zero, the instantaneous source voltage is at the peak. Once the current is interrupted, the voltage on the capacitor bank side of the breaker is at pre-interruption voltage peak. However, the source side voltage continues to change with sinusoidal characteristic. Thus, the TRV across the breaker contact could experience a higher magnitude equal to the twice of the source voltage. The TRV will eventually decay to the steady state power frequency source voltage level after the charges on cap bank eventually discharges.

In the interrupting process of the breaker, once the arc current passed through a zero-crossing point, the breaker attains a dielectric strength based on contact gap distance and the dielectric strength of the interrupting medium (SF6 gas in this application). The breaker maintaining a particular dielectric strength at a particular contact gap instant during opening process is determined by the rate of rise of dielectric strength (RRDS) of such breaker. RRDS capability of the breaker is normally determined by the region near zero arcing current crossing and also dictated by contact speed, dielectric properties and electrode design. Upon the breaker close, the RRDS will rapidly decrease to zero after the breaker main contacts close.

An uncontrolled or random opening may cause re-ignition in at least one phase of the circuit breaker. For controlled cap bank opening, the targeting strategy is to reduce arcing time and find the optimal breaker contact gap after current zero interruption such that the breaker contacts attain adequate dielectric strength (refer to Figure 9). By controlling the contact separation, re-ignitions can be eliminated. The optimal target point for current interruption is defined by contact separation range which brings a sufficient amount of time before the zero-crossing point of the current so that the contact gap at the end of the arc will be large enough to withstand the recovery voltage and thus avoid re-striking. But the contact separating moment should not be too early to avoid current chopping.

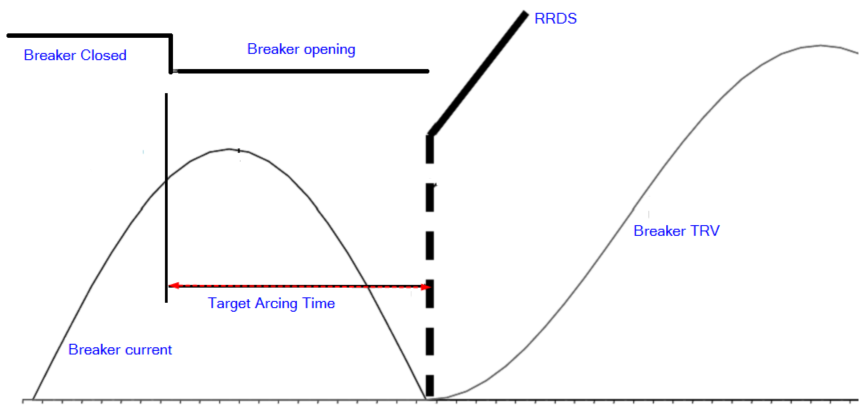

Figure 9: Controlled opening of a cap bank

The controlled opening operation controls the separation time of the movable and fixed contacts, for example, a few milliseconds before the current zero-crossing. So that when the current zero-crossing comes, there is a relatively large contact gap. The insulation strength increases to reduce the possibility of restrike, thereby avoiding the overvoltage phenomenon.

The implementation of the controlled opening process is shown in Figure 10.

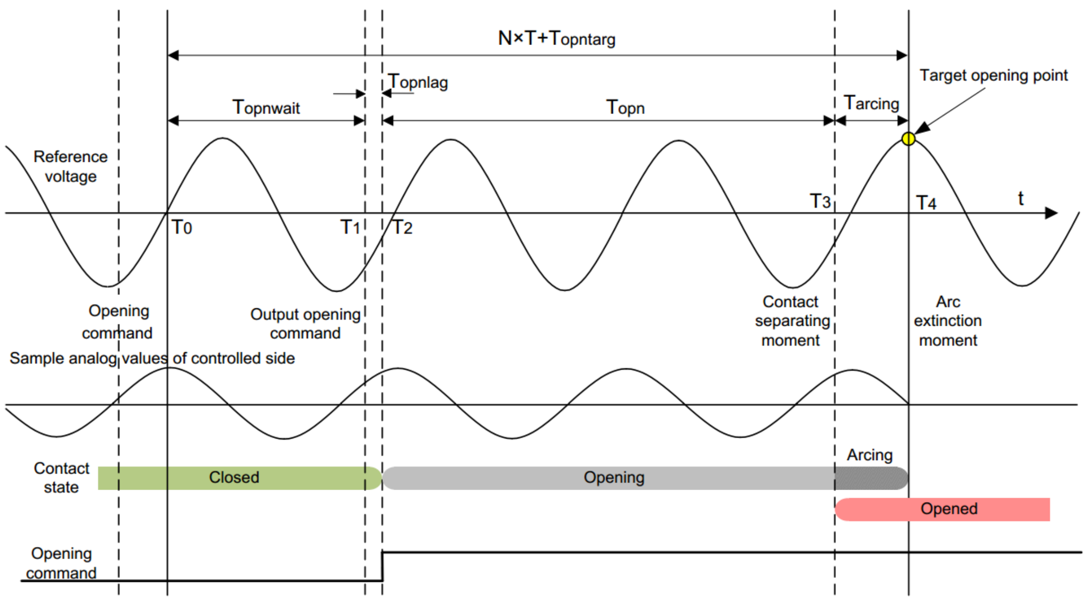

Figure 10: Controlled opening process

Where:

$T_{opnwait} = N \times T + T_{opntarg} - T_{opn} - T_{opnlag} - T_{arcing}$

N is an integer;

$T_{opnwait}$ is the waiting time of the controlled closing operation which considers the arcing time;

T is the period time of the reference voltage;

$T_{opntarg}$ is the time which is calculated from the target opening phase angle;

T_{opn} is the inherent opening time of the circuit breaker;

T_{opnlag} is the lag time of the opening circuit;

T_{arcing} is the arcing time.

The application example of SCU controlled breaker switching:

A 138kV 38MVAR 3-phase 60Hz capacitor bank with solidly grounded neutral is to be controlled by a SCU. The designed open and close time of the breaker main contact are 3-cycle and 5-cycle respectively.

Controlled Closing Process:

After receiving the external close command (BI_ClsCmd), the SCU device would calculate the sensed voltage & current on each phase basis. With the close wait time (Tclswait), the close commands from the device were sent to close coil of breaker poles. Figure 11 below shows the close control sequence.

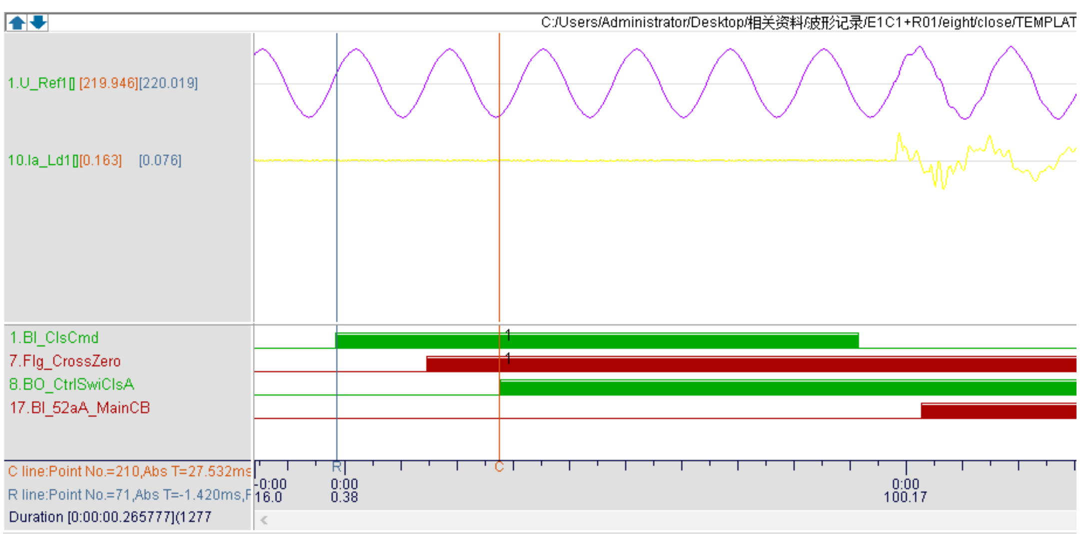

Figure 11. the breaker close control strategy

In the picture, the Tclswait = Tc-Tr = 27.532ms-1.420ms=26.112ms; so after the SCU device received the BI_ClsCmd signal and waited for 26.112ms. And then the binary output contact closed to close the CB. Figure 12 shows the waveforms of the voltage & the current.

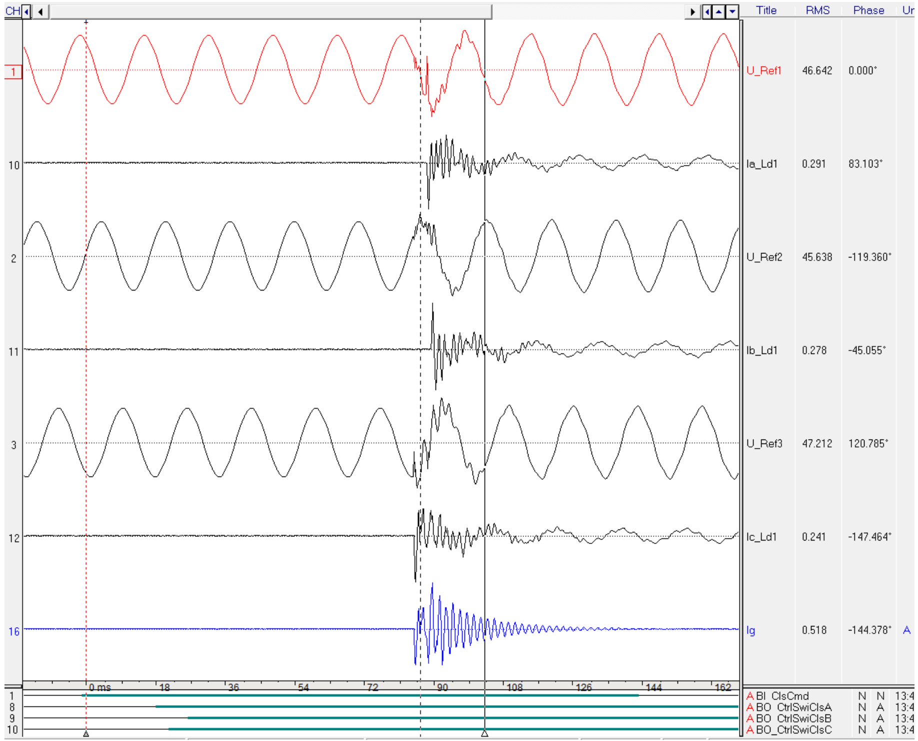

Figure 12. waveforms of the voltage & current following controlled closing

It can be seen from above diagram that the magnitude & duration of closing transients were minimized.

Controlled Opening Process:

After receiving the trip command (BI_OpnCmd), the device would calculate the sensed voltage & current on each phase basis. Considering the breaker inherent opening time, control circuit time constant, target opening phase angle and breaker arc time, the opening wait time (Tclswait) was calculated. Then the trip commands from the device were sent to trip coil of breaker poles so that the breaker current was interrupted at the peak of the reference voltage. Figure 13 shows the time difference between the external trip requirement to the SCU device and the actual trip command from the device.

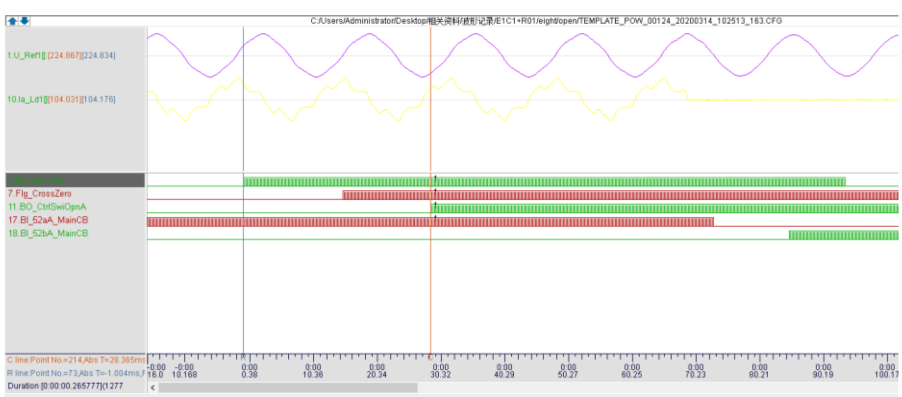

Figure 13. the breaker open control strategy

In the picture, the Topnwait = Tc-Tr = 28.365ms-1.004ms=27.361ms; so after the device received the BI_OpnCmd signal and waited for 27.361ms. And then the binary output contact closed to open the breaker.

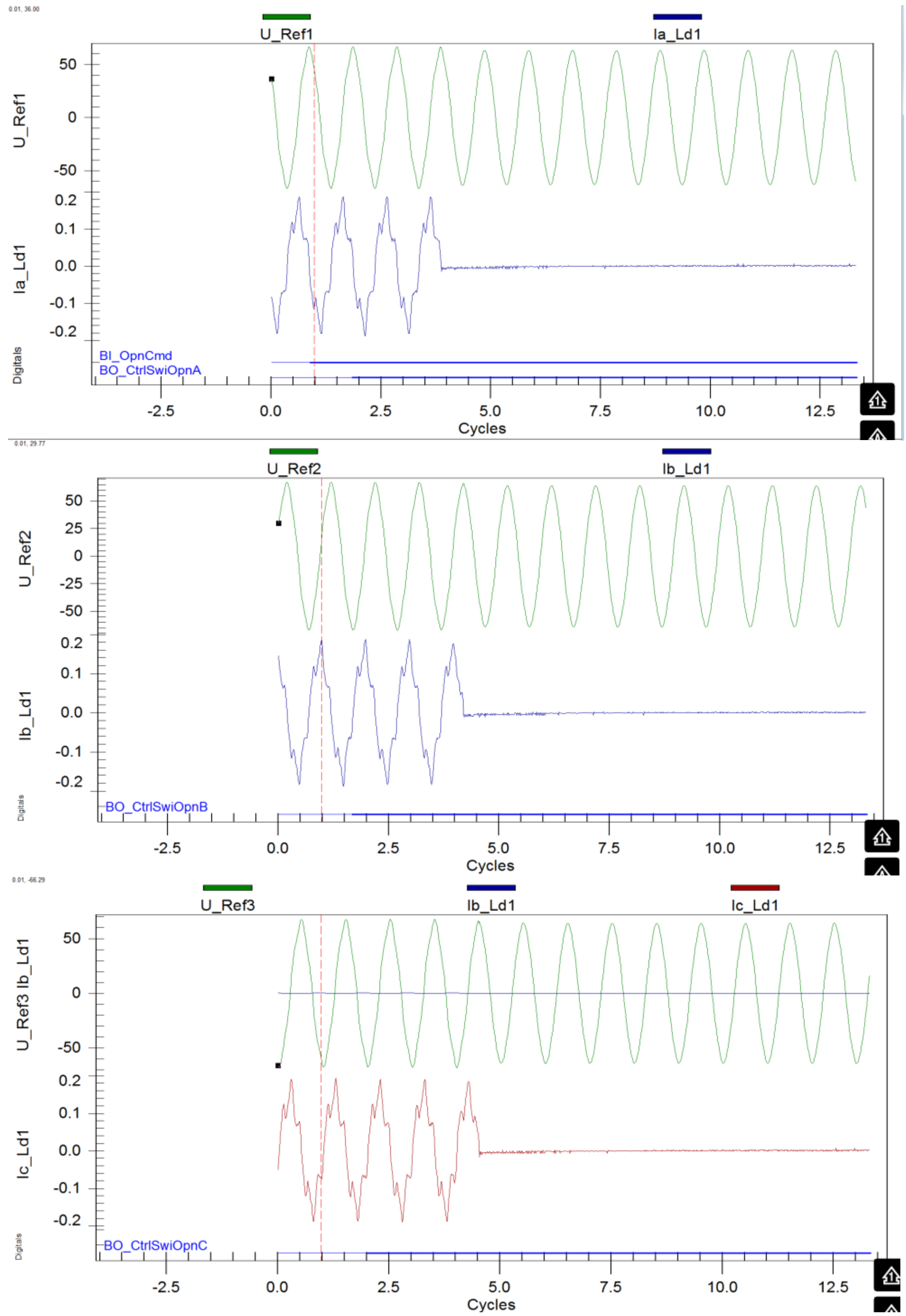

Figure 14. waveforms of the voltage & current following controlled opening

It can be seen from above diagram that the breaker opening process was very smooth and the restrike phenomenon were not present during breaker opening process.

Summary:

The switching operations in the power system will inevitably result in some degree of transients. Interrupting the low level of inductive or capacitive currents places high dielectric stresses on a circuit breaker. The controlled or synchronized switching of HV circuit breakers is an effective method of mitigating switching transients for the specific load and fault cases. The controlled opening command to the circuit breaker would reduce the arcing time of the main contacts during the operation and the less wear and the higher reliability of the breaker will be achieved.

References:

1. NR PCS-9830B Synchronous Control Unit (SCU) Instruction Manual

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