

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

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Introduction:

In modern society, electricity is indispensable 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.

Capacitor banks are provided at substations to regulate reactive power flow and voltage level of the power system. 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 operation and presents the root causes of the misoperation with the help of fault records 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.

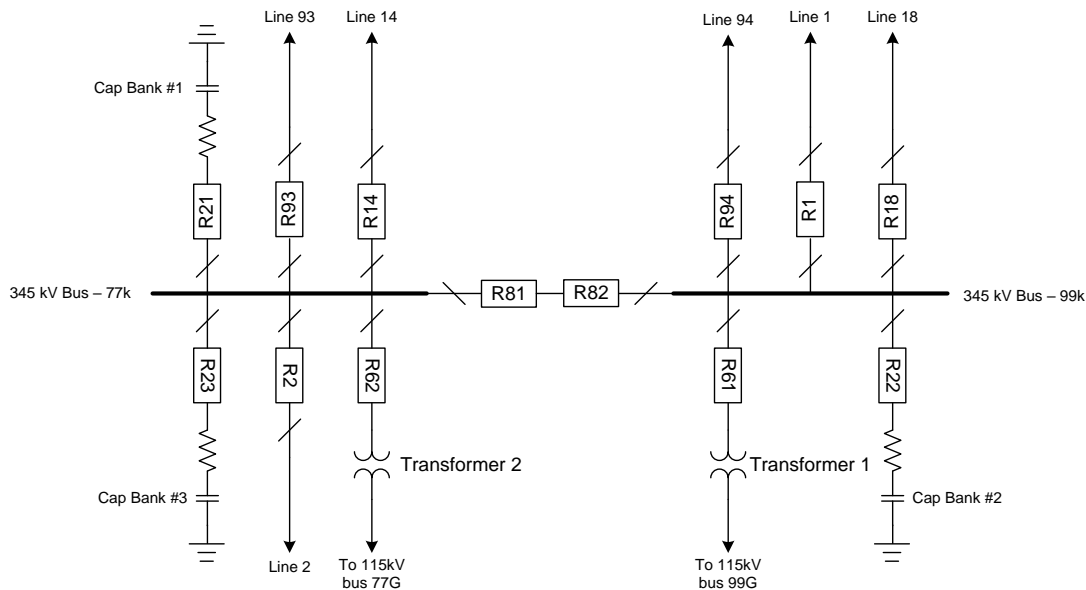


Figure 1: System one line of 345kV system at NS substation

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 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:

There were two separate events on February 16th of 2016 at NS substation.

At 01:53:13 AM on 2/16/2016, when the control center remotely sent a trip command to open 345kV breaker R21 feeding cap bank 1, the 345kV 77k bus was unexpectedly dumped coincident with R21 trip. Then, the dispatch restored the tripped 345kV bus 77k and its associated transmission lines and transformer breakers with the problematic cap bank breaker R21 isolated.

At 06:45:27 AM on 2/16/2016, breaker R18 on line 18, connected to 345kV bus 99k, was unexpectedly tripped coincident with the close of cap bank breaker R22 on bus 77k. During this event, a direct transfer trip (DTT) target was received. The remote station of line 18 confirmed there was no trip & fault at their end and no DTT was ever sent over to NS terminal.

The investigation of the first event:

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

2/16/2016 01:53:13	NS	345 BKR R21	BKR Open-Command
2/16/2016 01:53:14	NS	345 BKR R21	BKR Open
2/16/2016 01:53:15	NS	345 BKR R14	BKR Open
2/16/2016 01:53:15	NS	345 BKR R2	BKR Open
2/16/2016 01:53:15	NS	345 BKR R93	BKR Open
2/16/2016 01:53:15	NS	345 BKR R23	BKR Open
2/16/2016 01:53:15	NS	345 CAP1 86	ALRM Abnormal
2/16/2016 01:53:15	NS	345 BKR R21 TRB	ALRM Abnormal
2/16/2016 01:53:15	NS	345 BKR R62	BKR Open
2/16/2016 01:53:15	NS	345 BKR R81	BKR Open

Based on above SOE, the event can be summarized in the following sequence:

- 1) The operator at the dispatch center attempted to remove capacitor bank 1 from service by sending a trip command to its breaker R21 at 01:53:13 AM;
- 2) For whatever the reason, cap bank 1 breaker R21 was finally opened in approximately 1s after receiving the trip command;
- 3) Coincident with breaker R21 open, all other 345kV breakers connected to bus 77k were tripped;
- 4) In the meantime, a lock-out relay of cap bank 1 operated and breaker R21 initiated a trouble alarm.

The relay targets from the station trips are below:

- 1) 51AN

2) 50/62A

Both the residual overcurrent protection (51NA) of cap bank 1 and its breaker failure protection (50/62A) operated. After the operation of R21 breaker failure protection, all other breakers connected to the same 77k bus were correctly tripped.

Now a question arises, why did breaker failure relay of R21 operate since the breaker was to open by a manual trip command from a dispatch operator? A DFR record below from mid point PT of cap bank 1 disclosed the operation of backup residual overcurrent and breaker failure protection.

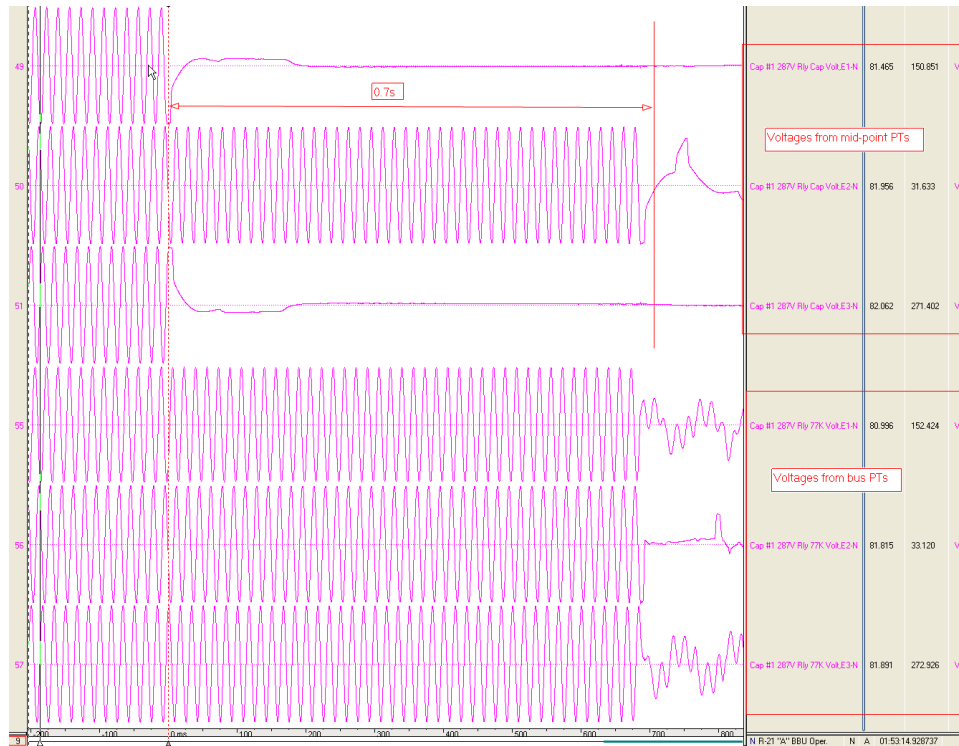


Figure 2: DFR recording showing the applied voltages for cap bank 1 prior to the trip

The first three analog channels (49, 50 & 51) are phase A, B & C secondary voltages from the mid point PTs of cap bank 1. Analog channels 55, 56 & 57 are PT secondary voltages from bus 77k. The waveform shows phase A & C voltage disappeared while B phase voltage lasted for another 0.7s, which indicates the A & C phase main contact of breaker R21 was opened after receiving the trip command and B phase main contact never tripped and remained closed. Once the breaker failure relay operated, the bus was tripped and the bus voltage disappeared. Since B-phase main contact of breaker R21 failed to open and the neutral of cap bank 1 is solidly grounded, the cap bank 1 was still energized on B-phase and the residual current (i.e. B-phase current) was present. The residual OC protections of cap bank 1 correctly tripped and operated the lock-out relay. As B-phase main contact of R21 remained closed after the trip command was received, the breaker failure protection of R21 correctly detected the failure of that breaker and tripped all the breakers on the associated bus. So far, the protections have operated correctly and no misoperations have occurred at the station.

The investigation of the second event and the over-trip of line 18:

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

2/15/2016 06:45:27 NS 345 BKR R23 BKR Close –Command

2/15/2016 06:45:29 NS 345 BKR R18 BKR Open
 2/15/2016 06:45:29 NS 345 BKR R23 BKR Close

After the trip of the 345kV 77k bus, the operator at the dispatch center successfully restored the bus system with the failed breaker R21 isolated. The system one line diagram is shown in Figure 3.

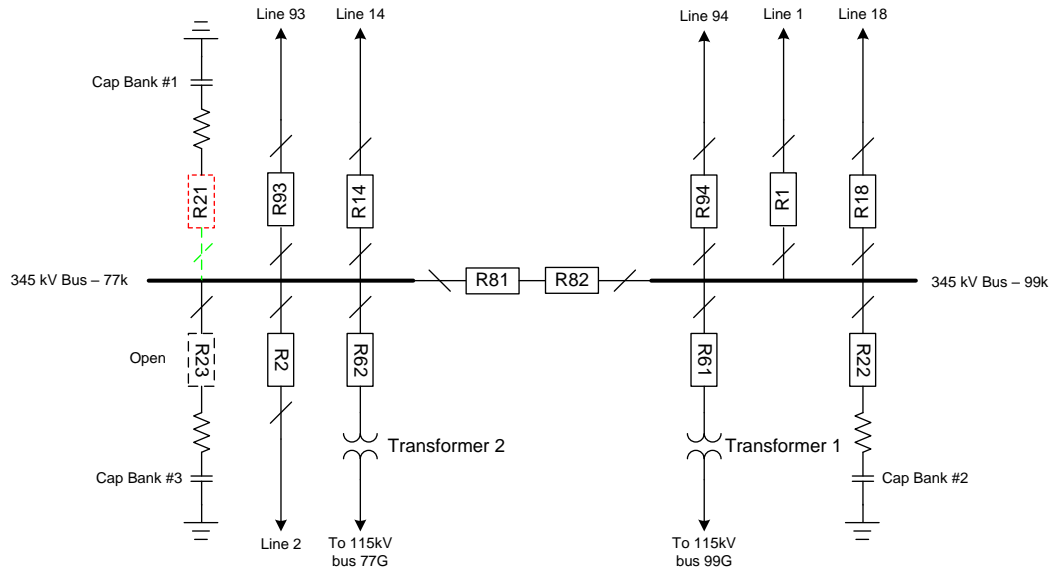


Figure 3: Configuration of the 345kV system at NS station prior to the second event

On 06:45:27 AM of 2/16/2016, the operator in the dispatch center issued a command to close breaker R23 on cap bank 3. When R23 was successfully closed, breaker R18 on the line 18, connected to 345kV 99k bus, was unexpectedly tripped. No apparent primary system abnormality was observed during the event. The only protective relay target on line 18 was direct transfer trips (DTT) receive. Both primary and secondary protection systems of line 18 were not triggered and no relay record was available. However, line 18 DTT relay recorded a record and it is shown figure 4 below.

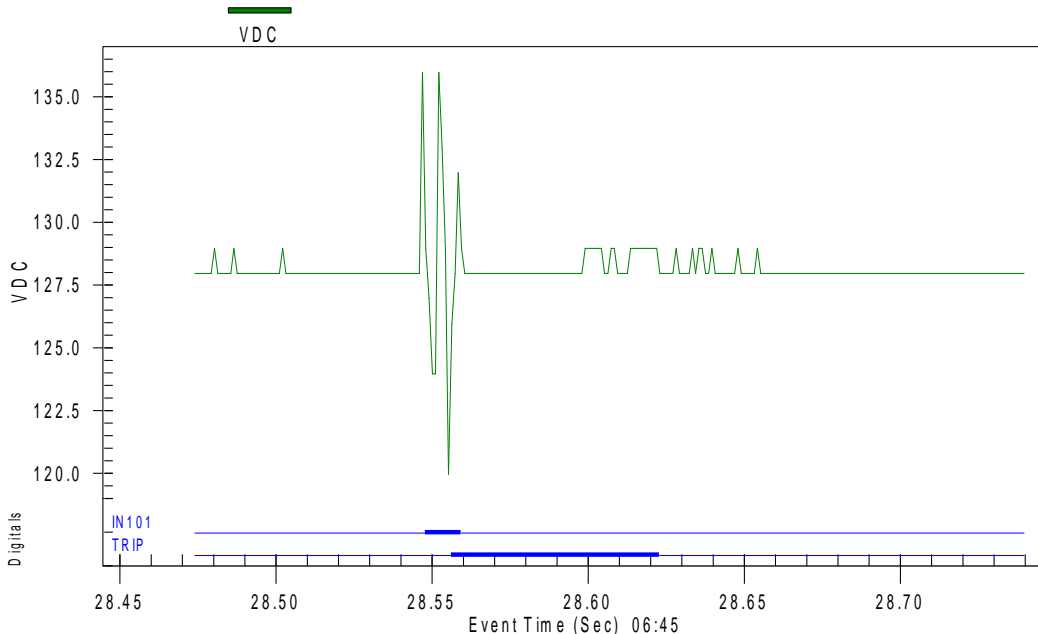


Figure 4: Record from line 18 DTT relay

As the relay trace shows, digital input IN101 was momentarily asserted during cap bank 3 switching. 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 line 18 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 R18 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 3 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 3 switching. Now it is the time to visit the DFR record to see the switching process of cap bank 3.

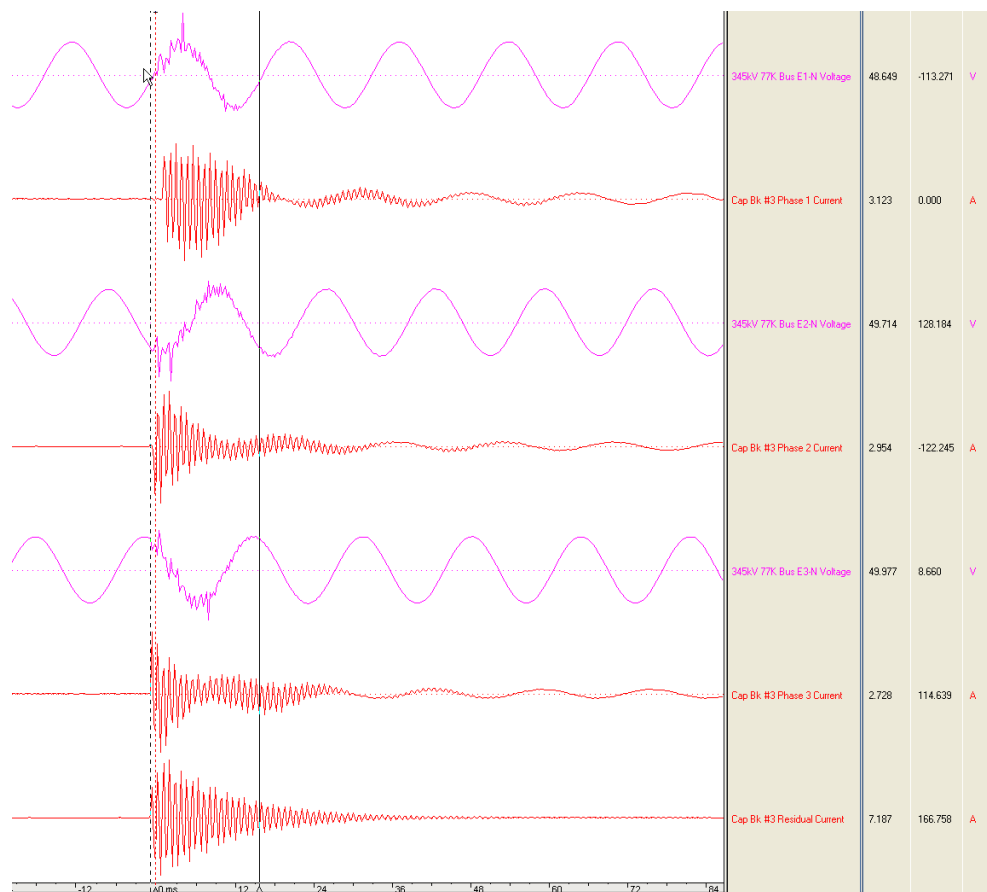


Figure 5: DFR records showing 345kV 77k bus voltage and cap bank 3 closing

Figure 5 shows 345kV 77k bus voltages and currents of cap bank 3 during the switching process. It can be seen that many transients were present in the current of the cap bank & approximately 2880A of residual current was in the cap bank neutral during the switching. The transient components in the current lasted for 3.5 cycles until it dissipated. Now let us look at the residual current of cap bank 3 and see what the level of harmonic distortion was during the event. Due to 3840Hz of the sample frequency of DFR, the maximum thirty second order of harmonic (1920

Hz) can be decomposed from cap bank 3 residual current. The harmonic table of cap bank 3 residual current is shown in Figure 6.

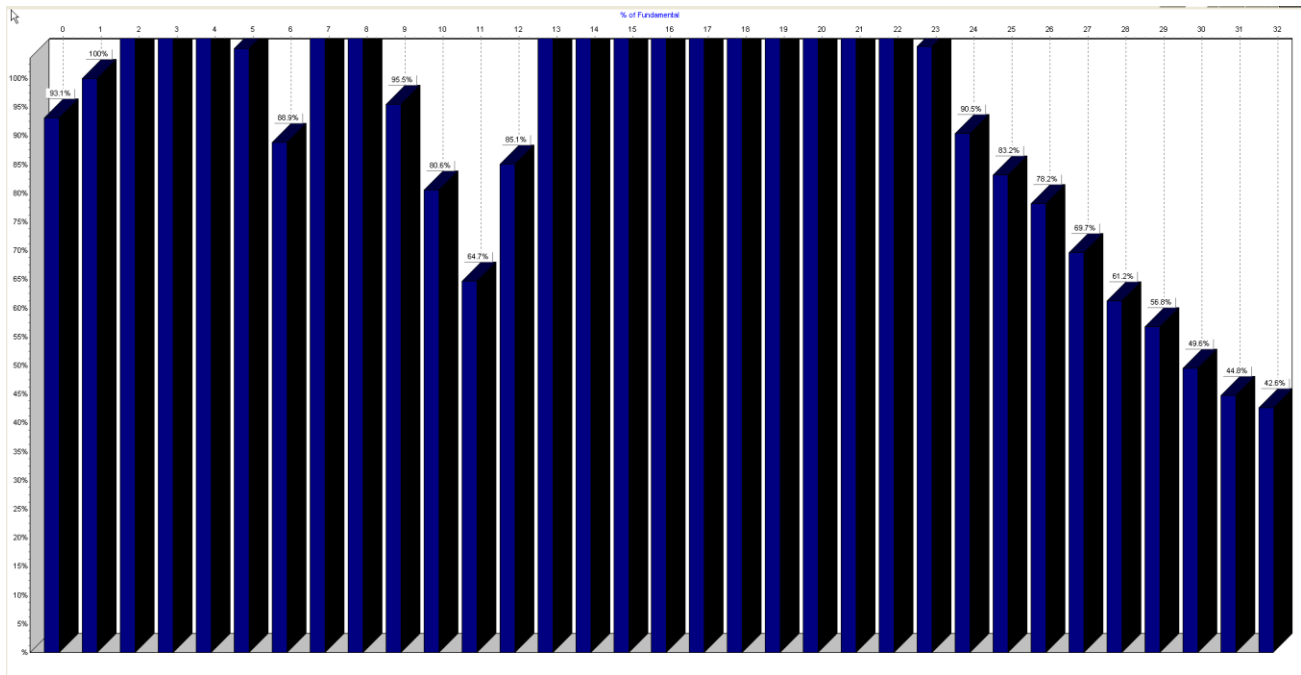


Figure 6: Harmonic components table of cap bank 3 residual current during switching

Per above analysis, huge amount of harmonics in both odd and even order were present in the neutral current of cap bank 3. During switching, the total harmonic distortion (THD) was 3761%. In other words, approximately 3000A of current with high component of harmonics were injected into the grounding grid of NS substation during the cap bank switching. This resulted in electromagnetic interference on DTT circuit of line 18 at the station. Since the cap bank breaker is controlled by a synchronous control unit (SCU), the voltage and current switching transients are supposed to be minimized during closing. But why there were still such high transients during the switching? After re-visiting Figure 5, it can be found that the poles of the breaker of cap bank 3 were NOT closed at the voltage zero across point of each phase. On the contrary, the breaker main contacts were closed randomly even though SCU was provided. Apparently, the SCU control malfunctioned during the cap bank switching. Now, it is time to take a look at synchronous switching control strategy.

Synchronous switching control:

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 a circuit, and thereby minimize the switching transients in the first place.

The purpose of an SCU for cap bank switching at NS station is to close the pole of the breaker individually at the voltage zero crossing on all three phases. Figure 7 shows a typical three phase AC waveforms in the positive sequence rotation (ABC), in which phase voltage A, C & B will have a zero crossing sequence in turn every 60 degrees or every 2.78ms in 60Hz AC system. The

SCU controller continuously monitors the phase voltage waveforms. When a close command is received, the controller determines at what point in time the breaker main contacts would be closed if the close coils were immediately energized.

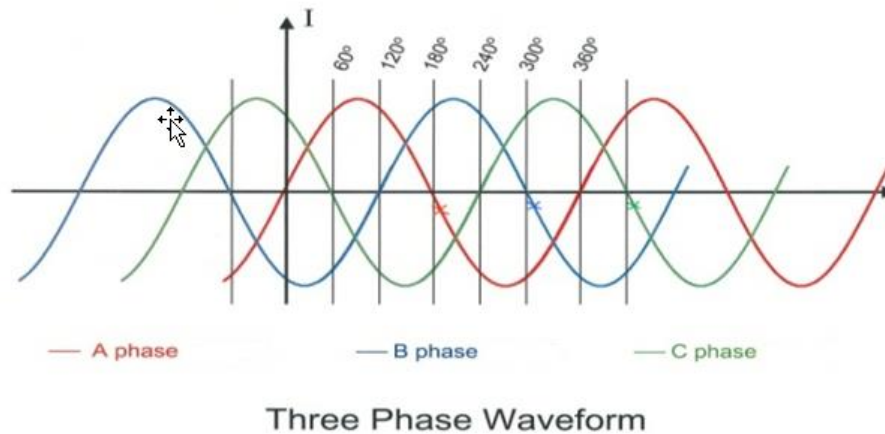


Figure 7: 3-phase AC waveform and zero crossing point

Should a voltage zero crossing occur and no other blocking conditions are detected, synchronous close commands to each phase are issued after a certain time delays. The time delays are measured from the reference zero crossing and compensated for breaker operating times and pre-strike characteristics. Then the current of each phase starts to flow at the corresponding interval (2.78 ms) with respect to the reference of zero crossing. Successful controlled switching will not only reduce the mechanical and electromagnetic stresses on the primary system, but also reduce the electromagnetic interferences on the secondary system in vicinity. However, we didn't have luck the SCU controller of cap bank 3 and apparently the SCU didn't function properly. Later, the manufacturer confirmed the SCU was damaged and had to be replaced.

Analysis of Capacitor Bank Switching Transients:

Considering a simplified Thevenin equivalent capacitor bank switching-on circuit shown in Figure 8, where V_s is the power system source voltage and R , L & C are resistance, reactance and capacitance of capacitor bank circuit respectively. To simply the analysis, the power source is assumed to be infinite bus with the zero equivalent impedance.

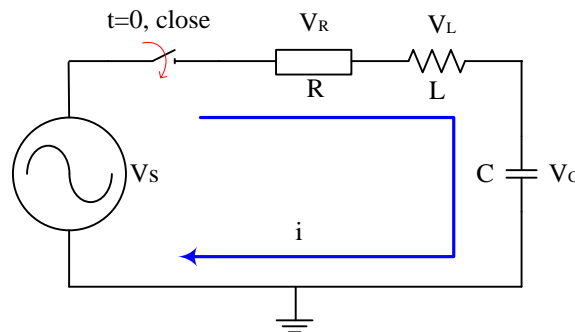


Figure 8: Equivalent circuit of capacitor bank switching

Per KVL, the following equation is always valid:

$$V_s = V_R + V_L + V_C \quad (1)$$

$$V_R = i(t) * R \quad (2)$$

$$V_L = L \frac{di(t)}{dt} \quad (3)$$

$$i(t) = C \frac{dV_C}{dt} \quad (4)$$

Where:

V_R , V_L & V_C are the voltage across the resistor, inductor and capacitor of the circuit;

$i(t)$ is the current in the circuit;

Now equation (1) can be re-written by using equation (2), (3) & (4) below:

$$LC \frac{d^2V_C}{dt^2} + RC \frac{dV_C}{dt} + V_C = V_s \quad (5)$$

The equation (5) is a second order differential equation because two energy storing components are involved in the circuit.

To define dampening coefficient α and un-damped resonant frequency ω_0 below:

$$\alpha = \frac{R}{2L}$$

$$\omega_0 = \frac{1}{\sqrt{LC}}$$

For reactive power compensation circuit, such as capacitor bank, the circuit design is normally under-damped in order to minimize the power losses and reduce the cost, i.e. the value of α is less than that of ω_0 .

The power system source voltage can be expressed in:

$$V_s(t) = V_m * \sin(\omega t + \varphi_{sc}) \quad (6)$$

Where:

V_m is the magnitude of the voltage;

ω is angular frequency of the system;

φ_{sc} is the voltage phase angle at the moment of energizing the circuit.

The steady-state of capacitor voltage (V_{CSS}) can be calculated in below:

The magnitude of capacitor voltage (V_{CM}) is

$$V_{CM} = \frac{V_m}{\sqrt{R^2 + (\omega L - \frac{1}{\omega C})^2}} * \frac{1}{\omega C} \quad (7)$$

$$\varphi_c = \varphi_{sc} - \frac{\pi}{2} - a \tan\left(\frac{\omega L - \frac{1}{\omega C}}{R}\right) \quad (8)$$

$$V_{CSS}(t) = V_{CM} * \sin(\omega t + \varphi_c) \quad (9)$$

The capacitor voltage including the damping transient components will be:

$$V_c(t) = (B_1 \sin \omega_d t + B_2 \cos \omega_d t) e^{-\alpha t} + V_{CM} * \sin(\omega t + \varphi_c) \quad (10)$$

Where:

$$B_1 = \frac{\alpha(V_{C0} - V_{CM} \sin \varphi_c) - \omega V_{CM} \cos \varphi_c}{\omega_d}$$

$$B_2 = V_{C0} - V_{CM} \sin \varphi_c$$

$$\omega_d = \sqrt{\omega_0^2 - \alpha^2}$$

V_{C0} is the initial voltage of capacitor; which is zero for our case.

Now the current in the capacitor bank can be constructed in the following equation:

$$i(t) = (\omega_d C B_1 \cos \omega_d t - \omega_d C B_2 \sin \omega_d t) e^{-\alpha t} - \alpha (B_1 \sin \omega_d t + B_2 \cos \omega_d t) e^{-\alpha t} + \omega C V_{CM} * \cos(\omega t + \varphi_c) \quad (11)$$

From above equation (11), it can be seen that not only fundamental frequency but also harmonic with angular frequency ω_d are present in the capacitor bank switching circuit. If the closing phase angle is large, the magnitude of inrush current could be a few thousand amps.

Under the stress of such large switching inrush current, the station bus voltage is always distorted with different order of harmonics. The actual bus voltage can be expressed with the equation:

$V_s(t) = V_{sm} \sin(\omega t + \varphi_{sc}) + V_{hm}(\omega_d t + \varphi_h)$; where V_{hm} and φ_h are the magnitude and phase angle of the h^{th} order of harmonics.

The above theoretical analysis is confirmed by the actual bus voltage and capacitor bank inrush current captured by DFR in Figure 5 & 6. Since SCU controller of R23 for capacitor bank 3 was damaged, the closing phase angle was random for each phase and it is not surprising to see approximately 3kA of residual current injected into the station grounding grid.

The interference to control cable by switching current at the station:

At the substation, the grounding grid system is required for safety reasons. An effective ground grid is designed to limit the voltage on the surface equipment in the substation area, thus the touch and step potentials inside the station can be limited to allowable values. The grounding grid also provides returning path for the ground fault current back to power source neutrals.

The grounding grid of the substation 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 9.

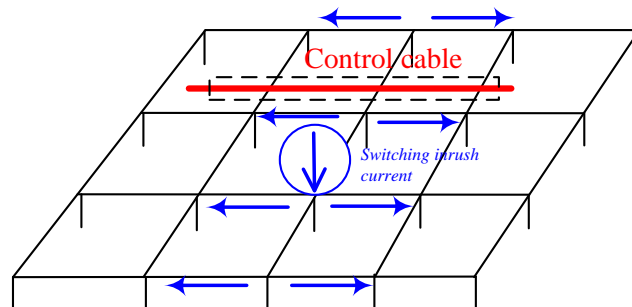


Figure 9: The typical layout of a substation grounding grid

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. Since the physical distributions of grounding grid conductors and control cable are complicated in the station, it is difficult to calculate the accurate induced voltage in the control circuit without using complicated simulation software. For qualitative analysis, we will use the lumped model for grounding grid conductors which have the mutual coupling with secondary control cable.

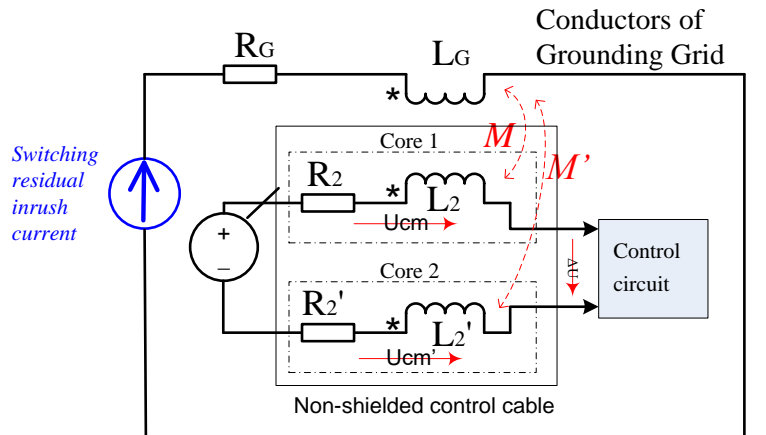


Figure 10: The mutual coupling between station ground grid conductors and control cable

Non-shielded control cables are used at NS substation. Figure 10 shows the simplified mutual coupling circuit between the lumped grounding grid conductor and control cable. The induced voltage on the core of control cables will be:

$$|E| = |j\omega MI|$$

Where I is the magnitude ground grid current, ω is angular frequency of current, M is mutual coupling coefficient.

Since the switching residual inrush current included a wide spectrum of harmonics, the induced voltage in control cable conductor would be the combination of harmonic voltages with high magnitude and it. Therefore, the induced voltages (U_{cm} & U_{cm}') would be present on the cords of the control cable, which are the common mode voltages for the control cable. As there exists small difference between the value of mutual inductances (M & M') and the small impedance difference in the signal circuit, the difference of common mode voltages ($\Delta U = U_{cm} - U_{cm}'$) created a differential mode voltage which appeared on the relay digital input and was higher than the triggering threshold. This can also be confirmed in Figure 4 that DC supply from a control cable got large fluctuations.

Following the latest National Grid technical standard for control cable specifications, shielded control cable shall be used in substations with voltage levels 230kV and above. Although control cable upgrades/replacements at NS substation were going on, unfortunately, this event happened.

Now we will look at why & how the shielded control shall be installed at the station and what will happen on the control circuit if the same switching event occurred.

- 1) The shielding layer of control cable is grounded at one end only:

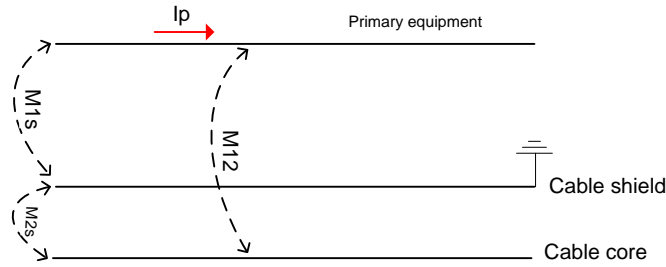


Figure 11: the shielded control cable with only one ground on shielding layer

Where:

M_{1s} – mutual inductance between primary equipment & control cable shield layer;

M_{2s} – mutual inductance between secondary control cable cord & shield layer;

M_{12} – mutual inductance between primary equipment & secondary control cable cord;

I_p – the current flowing through primary equipment;

When using shielded control cable and there is only one grounding point on the shield layer as shown on Figure 11, the induced voltage from primary equipment (such as station grounding grid) current on cable cord and cable shield layer would be:

$E_{12} = -j\omega M_{12} * I_p$ - induced voltage on control cable cord by primary equipment current

$E_{1s} = -j\omega M_{1s} * I_p$ - induced voltage on control cable shield by primary equipment current

Where:

$$\omega = 2 * \pi * f$$

E_{12} is induced voltage on control cable cord by primary equipment current;

E_{1s} is induced voltage on control cable shield by primary equipment current;

Since the physical distance between cable shield layer and its cord is small and distance between cable and primary equipment is relatively large, it can be considered M_{1s} nearly equals M_{12} ($M_{1s} = M_{12}$). Therefore $E_{12} = E_{1s}$; i.e. the same induced voltage will be developed on control cable shielding and center cord. This also means the shield layer of control cable doesn't change the induced voltage in the cable cord from primary equipment and it has the same effect as the non-shielded cable (so why should we spend extra money for shielded control cable?).

2) The shielding layer of control cable is grounded at both ends:

When using shielded control cable and shield layer are grounded at both ends, the current flowing through cable shield layer (I_s) is shown in Figure 12:

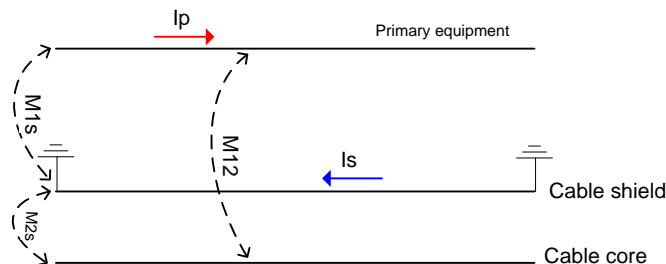


Figure 12: The shielded control cable with shielding layer grounded on both ends

$$I_s = E_{1s} / (R_s + j\omega L_s)$$

Where:

E_{1s} is induced voltage on control cable shield by primary equipment current;

R_s is the resistance of cable shield layer;
 L_s is the inductance of cable shield layer.

Since the induced current is present on cable shield, the induced voltage on cable cord by shield current would be:

$$E_{2s} = -j\omega M_{2s} I_s = -j\omega E_{1s} / (R_s + j\omega L_s) = (-j\omega M_{2s}) * (-jM_{1s} I_p) / (R_s + j\omega L_s).$$

Now the total induced voltage on cable cord from primary equipment and cable shield layer will be calculated by using superposing method:

$$E_2 = E_{12} + E_{2s} = -j\omega M_{12} I_p + \frac{(-j\omega M_{2s})(-j\omega M_{1s} I_p)}{(R_s + j\omega L_s)} \quad (12)$$

Since $M_{12} \approx M_{1s}$ due to physical approximation of control cable center core and shield layer and large spacing between control cable & primary equipment, equation (12) can be re-written below:

$$E_2 = -j\omega M_{12} I_p \left(1 - \frac{j\omega M_{2s}}{R_s + j\omega L_s}\right) \quad (13)$$

Now we can further look at the term $\left(1 - \frac{j\omega M_{2s}}{R_s + j\omega L_s}\right)$ of the equation (13) which is the total induced voltage on the control cable cord.

Because the physical distance between control cable core and its external shield layer is very small and almost all the flux produced by shield layer current has full linkages with cable center cord, it can be considered that mutual inductance between the core and shield layer (M_{2s}) nearly equals to the self inductance of shield layer (L_s), i.e. $L_s = M_{2s}$.

The term $\left(1 - \frac{j\omega M_{2s}}{R_s + j\omega L_s}\right)$ of equation (13) can be further simplified in below:

$$\left(1 - \frac{j\omega M_{2s}}{R_s + j\omega L_s}\right) = \frac{R_s + j\omega L_s - j\omega M_{2s}}{R_s + j\omega L_s} = \frac{R_s}{R_s + j\omega L_s} \quad (14)$$

For low frequency signals, the above equation approaches one as shown below.

$$\frac{R_s}{R_s + j\omega L_s} = \frac{R_s / L_s}{R_s / L_s + j\omega} \approx 1$$

That means the shielding or screen effects for low frequency noise signal is not that apparent.

However, for high frequency signals, the equation will be:

$$\frac{R_s}{R_s + j\omega L_s} = \frac{R_s / L_s}{R_s / L_s + j\omega} < 1$$

Therefore, grounding both ends of shield layer of control cable can effectively reduce the interference from high frequency noise signals on control cable conductors via magnetic coupling.

Additional benefits of using shielded control cable at the station:

It is well known that protection and control systems in a substation are exposed to a harsh environment which consists of different kinds of noise and disturbance sources. Many factors, such as the station switching operation, corona, partial discharges in the primary equipment,

lightning strikes, power frequency short circuit, etc. could cause a potential misoperation or even damage of protection & control system. The external noise signals can be coupled to the secondary circuit through capacitive, inductive, resistive and radiation paths. The nature of the noise and its frequency will determine the coupling path.

Using shielded control cable with proper shield grounding can effectively reduce the influences on the secondary circuit from the external high-frequency voltage noise via capacitive coupling path. Figure 13 shows the simplified capacitive coupling circuit between station primary and secondary circuit.

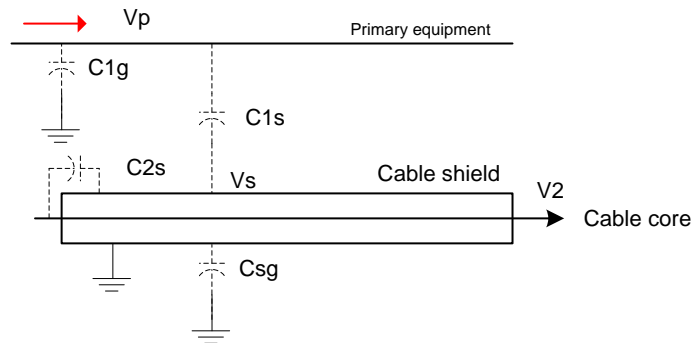


Figure 13: the capacitive coupling circuit between station primary and secondary circuit

Where:

C_{1g} – stray capacitance between primary equipment and ground;

C_{1s} – capacitance between primary equipment and cable shield;

C_{2s} – capacitance between cable core and cable shield;

C_{sg} – capacitance between cable shield and ground;

V_p – high frequency noise voltage on primary equipment;

V_s – cable shield voltage;

V_2 – the control cable voltage resulted from primary equipment;

The above circuit in Figure 13 can be re-drawn below:

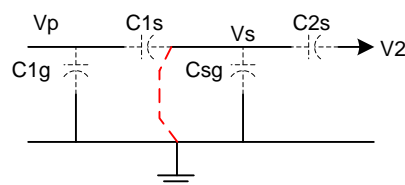


Figure 14: the equivalent circuit of capacitive coupling

If the cable shield layer is grounded, then the voltage on cable shield layer will be zero ($V_s = 0$) and the cable core voltage is zero as well ($V_2 = 0$). Grounding both ends of the cable shield will provide more security and reliability for hi-frequency voltage noises. Therefore, using shielded control cable with the shields grounded can effectively reject the external high-frequency voltage noise signals.

Other measures implemented on the protection scheme at NS station:

As shown in Figure (4), the line 18 DTT relay received a momentary false enabled signal from the induced voltage on control cable during capacitor bank 3 switching. The duration of the noise was approximately 0.8-cycle. To prevent this from happening again, the Transmission Planning Department was consulted to examine the possibility of “slow-down” a transfer trip from the remote of one cycle without affecting the system stability. The answer was “Yes”. So we introduced a 1-cycle time delay on the debounce timer of relay digital input, which would reject any noise signal less than one cycle.

Summary:

- 1) The SCU controller, if supplied, shall be carefully commissioned and periodically inspected to ensure the breaker poles are closed at the voltage zero crossing point to minimize the closing inrush current.
- 2) Based on above analysis, using shield control cable with both shield ends grounded can provide good protection against external noise at the substation.
- 3) When cable shield is grounded at both ends, the shield layer forms a loop for short circuit at the station and it might be burnt off when large current flows. It is recommended to install a parallel bare copper conductor (#4/0 AWG) alongside with control cables in the tray or conduit. The conductor can also help reduce the common mode voltages of the control cable.

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