Review of Capacitor Bank Control Practices

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I. Introduction

This paper reviews capacitor bank control options available in modern capacitor bank protective relays and common utility practices for the control of single or multiple shunt capacitor banks. A case study of Minnesota Power's approach to system wide capacitor bank automatic control is included. The purpose of the capacitor bank control is to switch the capacitor bank on or off in order to provide necessary reactive power or voltage support. There are, however, important considerations when planning and designing capacitor bank control schemes:

- Manual (local or remote) versus automatic control
- Automatic control based on time/season or measurement based automatic voltage regulation (AVR)
- AVR based on VARs, current, voltage or power factor
- Voltage drop compensation when important loads are located remotely from the bank measurement point
- Ability to lockout the bank until capacitors discharge to the safe level to energize bank again
- Ability to control the number and frequency of bank operations
- Ability to control bank closing to minimize transients
- Ability to coordinate the control of multiple banks with varying closing sequences

This paper examines the options above for switched capacitor banks and illustrates advantages and disadvantages of each option to help engineers choose the optimum approach for their application. The paper gives useful insights for engineers, helping them to enhance their schemes based on the available features in modern capacitor bank relays.

II. Overview of standards and regulations

Shunt capacitor banks are important for the reliable operation of the power system. The capacitor banks support the system voltage and reduce reactive power flow through the power system. In general, capacitor banks benefits are following [2]:

- Voltage support.
- VARs support
- Increased system capacity
- Reduced system power losses
- Reduced billing charges

There are a multitude of standards, guides and white papers that apply to the protection of shunt capacitor banks but there are relatively few standards or guides that apply to the control of shunt capacitor banks. Reference [2] defines Capacitor Control as “The device required to automatically operate the switching device(s) to energize and de-energize shunt power capacitor banks.” It also indicates that “Shunt capacitors support the system voltage and reduce the reactive current flow through the power system” and are “required when acceptable system voltages cannot be maintained by the generators and transmission system alone.” The IEEE considers capacitor control to operate automatically and are coordinated with generator voltage and power factor controls.

The North American Electric Reliability Corporation (NERC) reliability standard VAR-001-5 “Voltage and Reactive Control” requires transmission owners to develop a transmission voltage schedule and to “schedule sufficient reactive resources to regulate voltage levels under normal and Contingency conditions”. This regulation is to be accomplished through “reactive generation scheduling, transmission line and reactive resource switching, and using controllable load.” Reactive resource switching is not defined in the NERC standard but it likely includes the switching of shunt reactors and capacitors as well as the control of static VAR compensators (SVC). This scheduling will include both manual and automatic switching and is to be coordinated with the generator voltage and power factor controls.

While IEEE and NERC differ slightly in their requirements for shunt capacitor controls, this paper will consider both manual and automatic control of shunt capacitor banks to regulate voltage or power factor and will discuss coordination with generator controls and with transformer tap changer settings and controls.

III. Methods to control voltage/VARs

Shunt capacitors reduce the reactive power flow through the system and help support voltage. Acceptable voltage levels cannot be maintained only by the generators in the transmission system – shunt capacitor banks or other means of the reactive power are required. Mostly, power system loads are inductive and resistive, operating at the lagging power factor. Such loads require reactive power from the system, which means reactive power has to be transferred from generation causing system losses and reducing power system voltage because of these losses. Figure 1 below demonstrates effect of switching on the shunt capacitor bank.

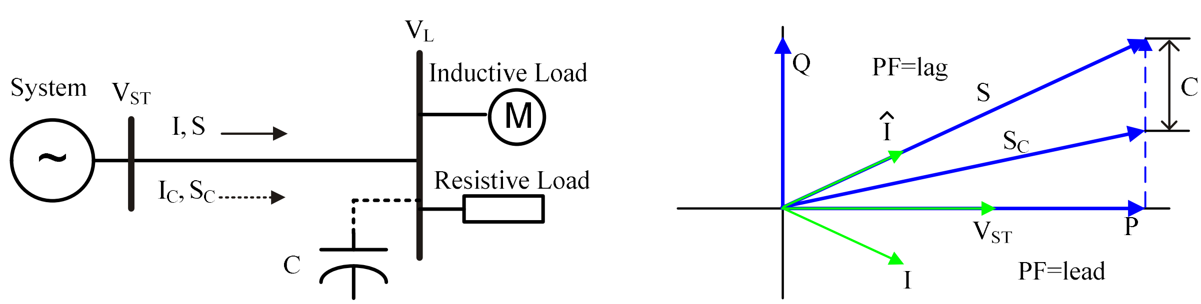

Figure 1. Effect of capacitor bank switching

From this figure the benefits of the capacitor bank switching on can be seen:

- it reduces reactive power required from the system by bank capacitance C
- it reduces reactive power plus apparent power flow through the line.
- inherently, current through the line will decrease from I to I_C and
- voltage at the bus V_L will increase because losses were decreased.
- power factor is improved with the capacitor bank switched on.

Depending on the application (transmission or distribution), location and power system parameters, availability of current/voltage measurements, bank size, availability of other bank nearby, availability of the load tap changer (LTC), etc., different approaches can be chosen to switch On/Off the capacitor bank by the capacitor bank controller.

There are a few common methods available in the capacitor bank controller to control voltage and VARs by switching capacitor bank On/Off.

- Timed control- capacitor bank will be switched On/Off depending on the time-of-the-day, day, month.
- Voltage measurement control– capacitor bank will be switched On/Off based on the measured voltage.
- Reactive power control – capacitor bank will be switched On/Off based on the measured VARs.
- Power factor control - capacitor bank will be switched On/Off based on the measured power factor.
- Temperature and current control – capacitor bank will be switched On/Off based on the measured current or temperature.
- Manual control – capacitor bank will be switched On/Off by the operator, based on needs.

We'll review these methods to elaborate on which method is most appropriate for certain application.

A. Time-based automatic control

Timed-based control is beneficial when the VAR demand pattern is well known during each day and during certain seasons. It minimizes the number of switching operations of the capacitor banks and therefore reduce switching transients, which improves power quality. An example is a large industrial plant, having the same VAR demand each working day of the week.

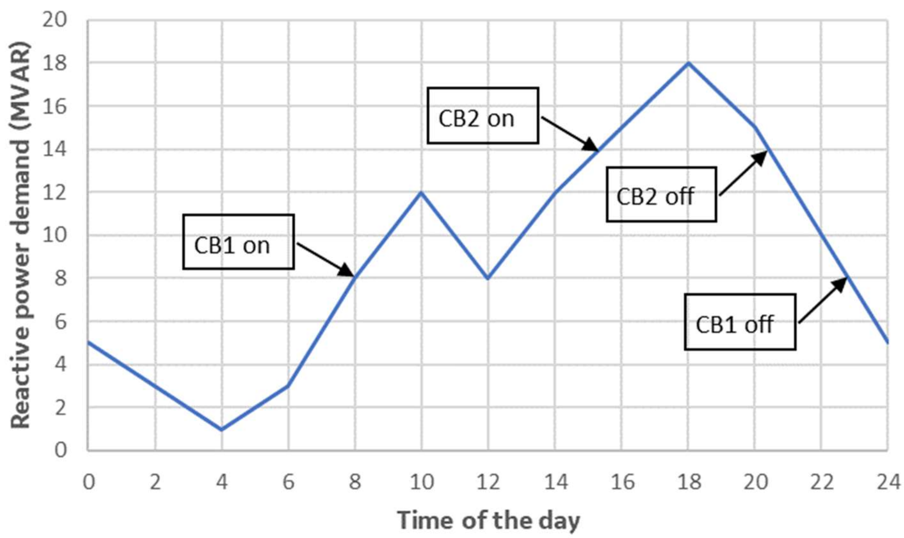

Figure 2. Example of the timed control to meet peak VAR demands

Figure 2 above illustrates an example of meeting MVAR demand in the area with 2 capacitor banks based on the time-of-the-day switching. Modern capacitor bank controller can be time-synchronized to the UTC time, providing the ability to program control actions based on the real time. Control actions can be programmed for the entire year using month-of-year, day-of-month, second-of-day functionality. This allows creating virtually any time-of-the-day and any season-based control actions.

B. Voltage measurement-based automatic control

Voltage measurement-based control is used when the capacitor bank is required to provide voltage support. Typically, capacitor banks with the primary objective of voltage support are installed at the major transmission and distribution buses serving large geographic area. Switching the capacitor bank in results in a voltage rise at the capacitor bank location, which can be estimated by the Equation 1.

$$\Delta V \approx \frac{I_C}{I_{SC}} \approx \frac{Q_C}{Q_{SC}} \times 100\% \qquad \text{Equation 1}$$

where I_C and Q_C are capacitor bank current and MVAR, while I_{SC} and Q_{SC} are system 3-phase short circuit current and system 3-phase short circuit MVA at the bank location.

Inherently, a capacitors bank controller, using voltage measurement control, will switch the bank On during peak loading conditions, causing increased system voltage and will switch bank Off during light load, causing decreased system voltage. To minimize effect on power quality for the customers, voltage change is recommended to be within 2-3% range for distribution systems and <5% for transmission systems.

For example, if system 3-phase short circuit power is 1000 MVA, switching on the 20 MVAR capacitor bank will result in 2% of the voltage increase at the bank location.

When a capacitor bank is located at a distribution station serving a critical customer located downstream on a radial line, the voltage level at the customer location may be significantly lower than the voltage level at the substation due to voltage drop along the line: $V_L = V_{ST} - I_L \times Z_L$. To maintain voltage at the customer location, voltage at the supply substation has to be higher and the controller has to take into account this voltage drop and turn On/Off the capacitor bank accordingly.

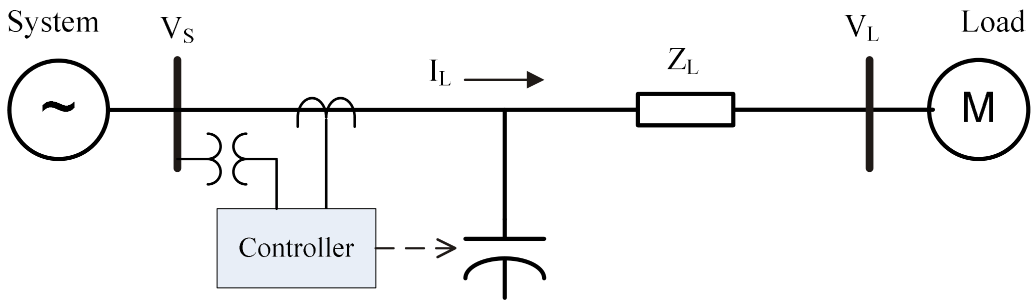

Figure 3. Voltage drop compensation

Modern capacitor bank controllers are able to estimate voltage level at the critical customer location by measured current and known feeder impedance, rather than at the substation bus and switch On/Off the capacitor bank accordingly.

When multiple banks are used to control voltage, it's important that all controllers respond to the same voltage, which may be selected in the controller as phase-to-phase voltage or phase-to-ground voltage, or the average of the three phase-to-phase voltages or positive sequence voltage. This will ensure all banks are controlling voltage in unison and there is no racing between them. Considerations to switch bank on or off in the voltage-based control mode are:

- Set the close voltage settings lower than the open voltage setting by more than the voltage change expected from capacitor switching, plus margin.
- Coordinate between multiple banks in the area, which is achieved by proper voltage level setting value and time delay to switch bank on or off.
- Coordinate with a load tap changer (LTC), when using this mode in the distribution substation. Load tap changer will increase voltage but will not improve reactive power flow and power factor at the substation. Therefore, capacitor bank should have a preference over LTC, especially at the distribution substation, supplying industrial load - this is achieved with a proper time delay at both controllers. Also, capacitor bank controller should use voltage from the HV side, while LTC controller from the LV side of the transformer, regulated by the LTC.

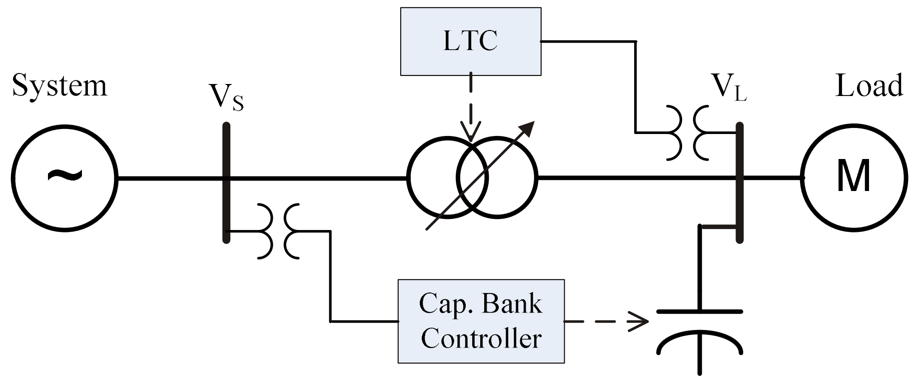

Figure 4. Coordination between LTC and capacitor bank controller

Figure 4 above depicts voltage measurements for coordination between LTC and capacitor bank controller. Usually, onload tap changers regulate voltage in steps of 0.625% to 2.5% with a time delay 1-3 minutes for each step operation but switching on a capacitor bank can give the same or larger voltage increase much faster. Therefore, it is important to exclude possible counter action between these two control devices, where switching On the capacitor bank can cause the LTC to decrease a tap and vice versa. Frequent LTC operations are not desirable because they reduce LTC lifetime, increase maintenance cost and cause voltage step changes at the customers. One approach would be for the LTC controller to check capacitor bank status and increase step change delay after a capacitor bank switching operation. Another approach would be to switch On the capacitor bank(s) permanently during high load time and allow tap changer to fine adjust the voltage during this time. Properly sizing the capacitor bank or dividing one large bank into multiple smaller banks can also improve coordination with the LTC.

C. Reactive power-based control

Reactive power-based automatic control directly provides all benefits of the shunt capacitor banks such as: improved voltage, improved power factor, reduced system losses, increased system power transfer capacity and reduced reactive power requirements from generators. This control mode can be used on both transmission and distribution substations. Reference [2] gives details of the economic impact of adding capacitor bank to the system.

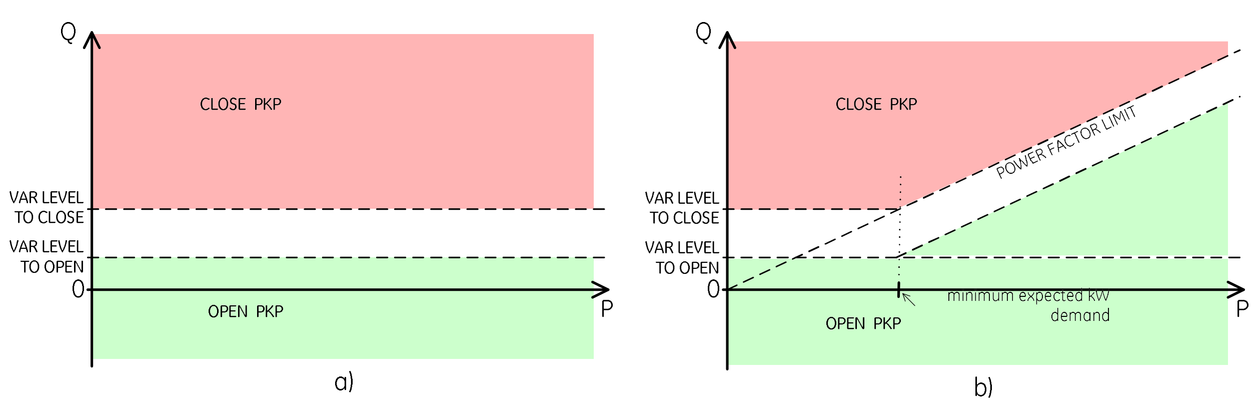

Figure 5. VAR control mode without (a) and with (b) PF supervision

Reactive power-based control can be used to regulate both VARs and power factor of a load to reduce transmission and distribution costs. If the capacitor bank's primary objective is to minimize system power losses, then power factor supervision is not used, and the characteristics will look like in Figure 5a. When the primary objective is to minimize power factor rate penalties, then power factor supervision is used, and the characteristics will look like in Figure 5b. Larger margins between VAR Close and VAR Open result in less frequent capacitor bank switching. The difference between VAR Open level and VAR Close level should be the amount equal to the capacitor bank VAR rating plus a margin.

D. Power factor-based control

Although it's looking attractive to use power factor for automatic switching to avoid penalties for the low power factor, in general, power factor alone is not a good basis to control capacitor bank switching [2]. This is because power factor measurement itself cannot distinguish between low load and high load, which may result in the leading power factor due to "fixed" size of the capacitor banks. At low load it can also cause a "pumping" condition because adding capacitor bank can easily cause a significant change of the power factor. At high loads it may be beneficial to use power factor-based control, which requires adding VAR or current measurement to a control mode. Therefore, the method described in [C] above is more attractive to use both VARs and power factor together. If, however, user has a need to automatically control a capacitor bank using power factor-based control, modern controllers provide this functionality.

E. Temperature and current-based control

Although temperature and current magnitude increases are an indication of the VAR demand, they are not giving direct measurement of the VARs deficit at the given bus or geographic area. Therefore, these methods are not preferred when measurements of the voltage and current are available and when the capacitor bank controller is capable of methods A to C described above. However, it's still possible when direct correlation between temperature/current and voltage/VAR change is well known.

F. Manual control

Manual control, local or remote, still can be used by the operator for switching the capacitor bank On/Off depending on system conditions. Sometimes, due to scheduled maintenance of the VARs resources, it is known in advance that a VARs deficit is imminent and is desirable to have capacitor bank(s) switched On in advance. With the communications available today, remote control is very much possible, but local control may be needed as well in case of communications failures and emergency situation. Automatic, manual and remote controls have to be interlocked not to contradict each other which will be discussed in the section V below.

IV. Transients control

The capacitor bank controller is directly controlling switching devices, which are HV circuit breakers or circuit switchers. Capacitor switching devices require special attention because very severe switching transients exist during both switching on and off the shunt capacitor banks, affecting both the capacitor bank and the adjacent system.

Energization of the shunt capacitor bank creates severe transient over-voltages, affecting insulation of the adjacent equipment. The most severe over-voltage occurs in the phase, which is closed at the voltage peak. Figure 6 below illustrates an example of a 230kV 26MVAR bank energization where all 3 breaker poles were closed simultaneously with phase A at the voltage peak. Over-voltage in phase A reached 1.85pu, while phases B and C experienced very small overvoltage.

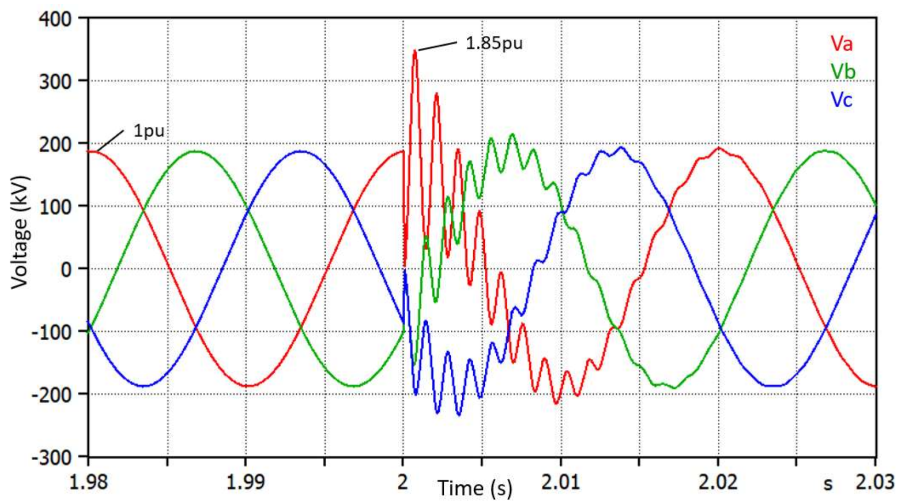

Figure 6. Overvoltage during capacitor bank energization

Although these over-voltages are below utility surge protection, they will pass through step-down transformers to lower voltage loads. To reduce these over-voltages, it is desirable to energize each phase separately close to voltage zero-crossings, if the breaker and the capacitor bank controller are capable to do so. Typically, capacitor bank energization transient frequencies are from 300Hz to 1kHz [2]. Figure 7 below demonstrates the single bank energization current inrush. When a capacitor bank is energized in the proximity of the previously energized capacitor bank, sympathetic inrush currents frequency and magnitude will be even higher than the isolated bank energization and can be mitigated with the addition of a small series reactor on the second bank.

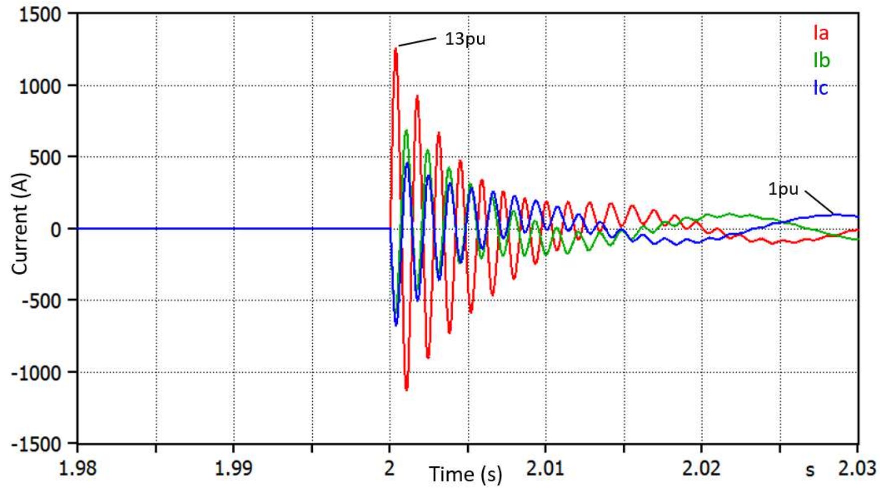

Figure 7. Overvoltage during capacitor bank energization

Another important concern is de-energization of the capacitor bank. When the breaker opens, capacitors remain charged at whatever instantaneous voltage value they were left disconnected. Across the breaker contacts there is now the bus sinusoidal voltage and the constant voltage of the capacitors. The worst case is when voltage is interrupted at the phase voltage peak, because capacitors remain charged initially at this value and 2 times peak system line to ground voltage (2pu) appears across the breaker contact. A dielectric breakdown in the gap between the breaker contact results in the resumption of current through the breaker contacts causing a restrike. Figure 8 below demonstrates field case capacitor bank breaker restrike. It can be seen that restrike is happening in phases B and C which were interrupted close to the corresponding phase peak voltage. Phase A was interrupted close to zero-crossing – no restrike occurred.

Undetected breaker restrike will cause damage to the dielectric withstand of the breaker insulation and may eventually lead to a catastrophic breaker failure. Capacitor bank controllers should be able to detect and alarm on each occurrence of the restrike. Reference [2] gives recommendations for controlled switching, where, for a grounded bank each phase should be closed individually on the phase zero-crossing and for an ungrounded bank the first 2 phases should be closed first on the phase-to-phase voltage zero and then delaying closing the 3rd phase by 90°.

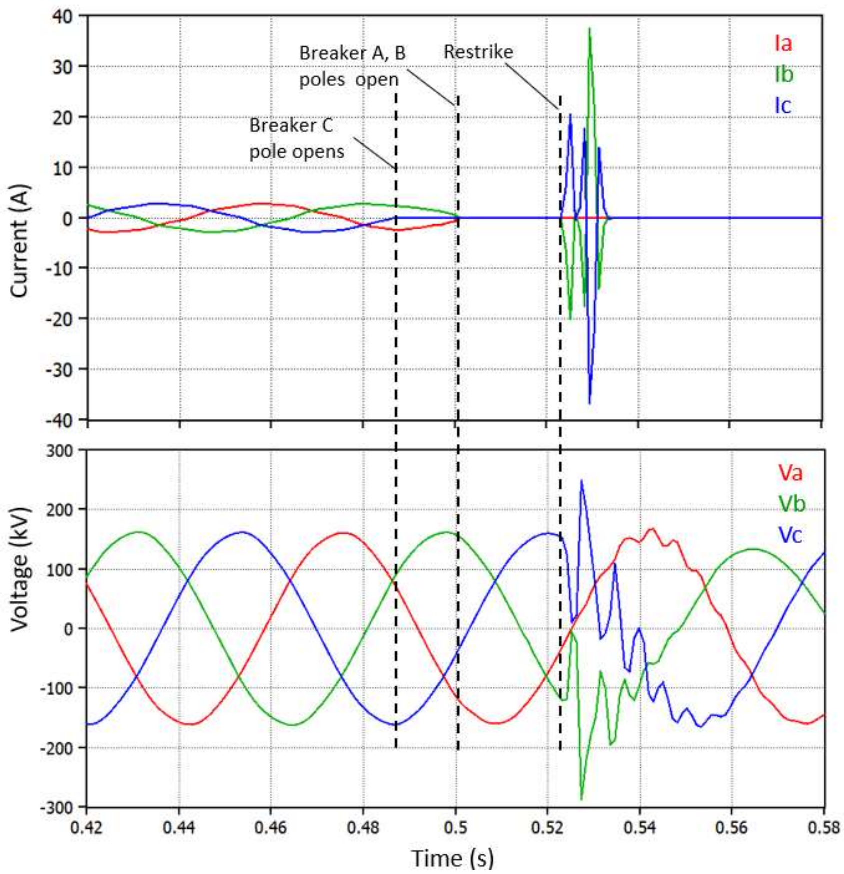

Figure 8. Breaker restrike during capacitor bank de-energization

It is important to remember that capacitors remain charged for a long time after bank de-energization - attempt to re-connect the bank with capacitors having significant trapped charge may result in even more severe transient over-voltages and increased duties on the capacitor bank breaker. Interlocks to delay re-energization are required. This will be discussed in the section V below

V. Interlocking

The capacitor bank controller needs to switch the bank On/Off to ensure safety of the personnel and equipment. To achieve this, the capacitor bank controller needs to have the means to provide interlocking between close/open commands from different sources and needs to open or close the bank at optimal time.

A. Discharge Interlock

Capacitors store energy in the form of electric fields. This necessitates precautions when energizing and deenergizing capacitor banks. Capacitor elements are not ideal capacitors so, given enough time, they will discharge any trapped charge following a de-energization. However, the rate of time required to discharge the trapped charge is unpredictable and quite long. For this reason, individual capacitor can design includes an internal discharge resistor as shown in Figure 9 which will dissipate trapped charge to less than 50V within 5 minutes.

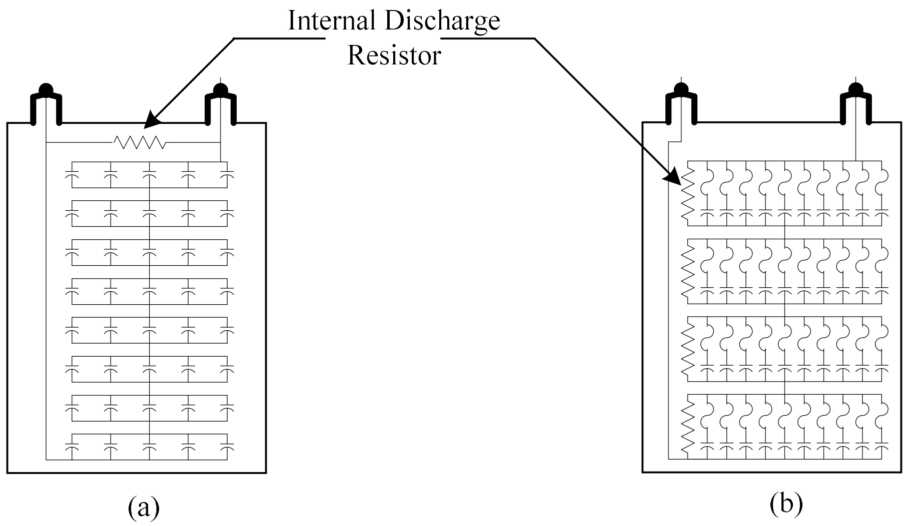

Figure 9. Fuseless (a) and internally fused (b) capacitor cans discharge resistors

To allow the resistor time to discharge any trapped charge, a time delay is required to inhibit closing after the bank has been switched Off. Even though a 5 minutes delay is frequently used [2] in the industry, re-energizing capacitor sooner or later may be required and [1] gives details of the discharge time calculations.

B. Manual/Remote/Auto Control Interlocks

Capacitor control includes On/Off commands from various sources (protective trips, local/remote/auto commands, etc.). It is important, for safety and administrative reasons, that the control maintain remote/local and auto/manual control rights. Local control refers to control from the front panel of the relay or relay panel. Remote control refers to control via communications from an on-site interface, and/or from an off-site control system (SCADA, master VAR management system, etc.).

Auto control allows the capacitor control system's automatic control system On/Off control of the capacitor bank switching device. Manual plus Remote allows remote control and Manual plus Local allows local control. In some cases, it is desirable to force the auto/manual mode to manual on a protection operation to prevent the control system's automatic switching scheme from closing a faulted capacitor or where closing the bank might cause cycling. This is especially important for trips like bus over-voltage where the protection does not operate the capacitor bank lockout device. For safety reasons, the local off (trip) control is typically always active. When this is the case, it is also necessary to toggle the control to Manual following a local off (see Figure 10 for example logic).

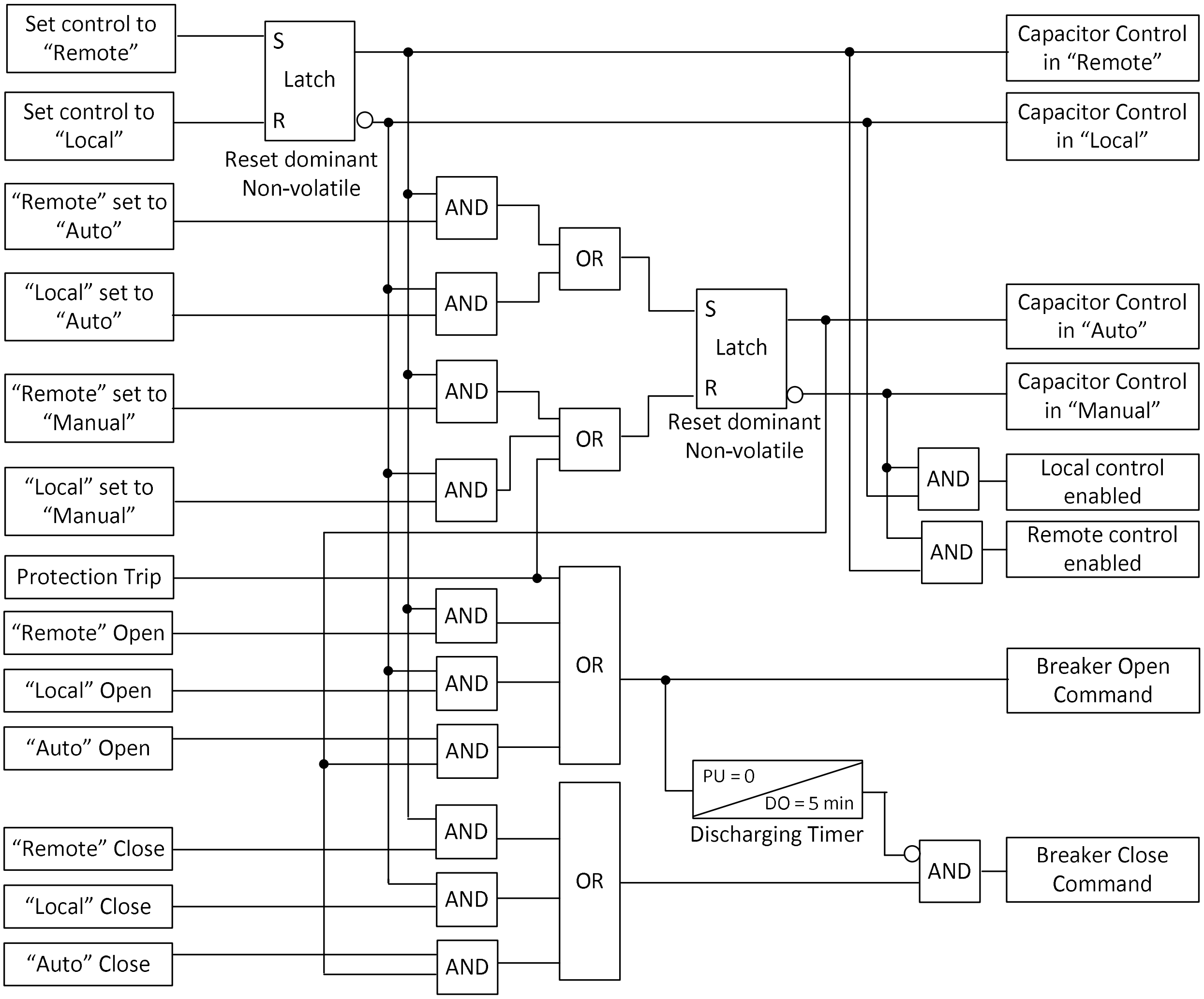

Figure 10. Example logic for Manual/Remote/Auto control interlocking

In the example logic above, there is always a "conscious" decision and indication about who has a control priority, either local operator, or remote operator or controller left to control automatically per control mode programmed. Another important consideration is controlling the number of switching operations of the capacitor bank – the controller may include a lockout timer after each close operation or count and then limit number of operations per day.

C. Bus and Line Loss-of-Voltage Off interlock

In many cases it is desirable to open the capacitor bank switching device when the connection point to the system de-energizes. This prevents re-energization of the bank when the connection point re-energizes. This is especially important when the connection point is a line or a portion of the bus that de-energizes for a line fault and the connection point is subject to automatic reclosing. Opening the switching device enables the Discharge Interlock logic, discussed previously to assure the capacitors are fully discharged before re-energization. This is easily accomplished by tripping the switching device with an under-voltage element set to operate on total loss of connection point voltage with a time delay less than the line reclosing time.

VI. Optimizing multiple banks control and coordination with other Volt/VAR controls

It's quite simple to apply a controller to automatically control a single capacitor bank at the substation bus. It is, however, a rare case that this is the only Volt/VAR regulating means in the area. Usually, there are many capacitor banks and other VAR regulating apparatus on the transmission, sub-transmission and distribution substations. Besides VAR regulating means, there are transformer load tap changers, regulating voltage at the LV buses. Therefore, Volt/VAR regulating problem becomes multi-dimensional and very complicated.

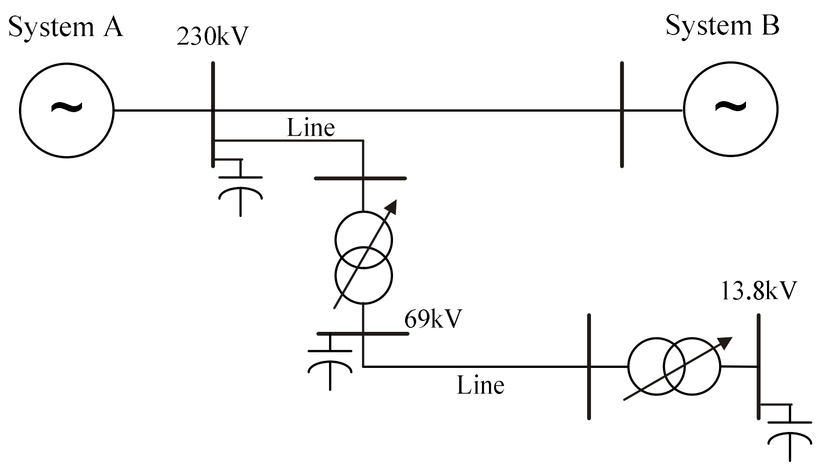

Figure 11. Multiple Volt/VAR resources in the power system

Another requirement is to keep the number of switching operations for both capacitor banks and LTCs as low as possible to extend the life of switching devices. There are optimization programs available for the system planner which allow analysis of multiple approaches to control voltage, reactive power, losses, minimize switching and select the best one to meet all these objectives. Therefore, P&C engineers need to program capacitor bank controllers in accordance with system planning requirements.

VII. A Case Study: Minnesota Power's approach to system wide capacitor bank automatic control

A. Overview of the Minnesota Power and MISO systems

Minnesota Power (MP) is a vertically integrated electric utility located in northeast Minnesota. MP controls all aspects of electric service from generation, transmission, to distribution. The utilities' generation resource mix includes large coal fired plants, natural gas or biomass peaking plants, hydroelectric facilities, and wind farms. The MP transmission system includes voltages from 500KV down to 115KV, and encompasses over 2100 line miles. The peak load served by MP is approximately 1800MW and can be approached in either summer or winter conditions. MP is somewhat unique in its system loading levels because of both its ability to peak under summer or winter conditions and its high capacity factor. While similar to most utilities that experience peak load under hot summer temperatures, MP is also geographically located in northern Minnesota where extended cold winter conditions drives high winter customer demand. The high capacity factor is due to 12 industrial customers accounting for approximately 60% of the consumed load. While these industrial loads remain relatively constant in magnitude and are unaffected by time of day or season, the same is not true for MP residential load or regional transfers through the MP service territory. These transfers are the result of MP being uniquely situated between the wind resources of the western planes, the hydro generation resources of Manitoba, and the large load center of the Minneapolis/St. Paul, Minnesota metropolitan area. Due to the variability of the wind and potential to store water for future use, the regional transmission transfers or transmission line loading levels can vary significantly on a daily basis. As noted in this paper, variable transmission line loading results in similarly variable reactive power requirements.

MP is a member of the Midcontinent Independent System Operator (MISO) which is a Regional Transmission Organization (RTO) that oversees reliability and market services to utilities in 16 states and provinces including almost 66,000 miles of transmission lines. MP coordinates with MISO continuously to ensure reliable operations across its service territory which involves operating and planning for reactive power needs.

B. Planning Criteria

MP plans and operates its transmission system to meet local and regional criteria. Generally speaking, the MP designated planning horizon criteria is the most stringent. One of the benefits of this is that it allows for additional margin and flexibility in real-time operations, specifically during abnormal conditions. The MP planning criteria for voltage is that the steady state voltage regulation shall be between 1.0 and 1.05 pu. Additionally, the voltage must remain between 0.95 and 1.10 pu while following a transmission level contingency and return to steady state levels within 30 minutes. The rational for maintaining a higher steady state voltage of at least 1.0 pu is related to the desire to provide MP's industrial customers with robust voltage support on a continuous basis. MISO allows member utilities to specify their own criteria limits for operations and planning but does offer guideline limits based on normal or good utility practice. These limits align with MP's operating criteria of + and - 5% of nominal for steady state, and + and – 10% of nominal for contingent operation. While it is MP's practice to maintain all operating voltages to a level of at least 1.0 pu, it is not always possible based on automatic equipment settings which will be described in further detail below.

C. Study Method

MISO along with MP perform yearly planning assessments looking at future system needs based on a wide range of assumptions. A wide range a reactive resource scenarios can be examined at a very board level to assure existing resources are capable of meeting criteria levels for voltage control by creating detailed future-looking power flow models that include real and reactive loads; reactive resource capabilities; generation unit statuses and dispatch levels; transmission outages, transfer levels; etc. When new facilities are proposed, a detailed local area assessment is completed to understand the unique needs required by those facilities. Recent examples of this on the MP system include the addition of a new 500KV transmission line that required a shunt capacitor bank to provide reactive power during high transfer conditions and four capacitor banks that were required as part of the staged retirement of a number of small coal-fired generation facilities. The four banks were needed to cover a transition period where a limited amount of generation was available and before the final mitigation of a STATCOM could be installed. Once commissioned, the STATCOM assumed functional control of the capacitor banks which are now coordinated to extend the useful range of the facility. However, during the interim period when the capacitors were the primary reactive resources available, extensive study work was performed to develop fast and slow insertion times in order to satisfy steady state, post-contingent and transient stability needs.

During these local assessments new reactive power needs projects are reviewed and the bank size, timing requirements for switching, and control strategy are developed. As these details are developed they can be tested for compliance based on broad regional-level impacts. This bottom-up or local-to-regional approach to planning best suites Minnesota Power's needs.

D. Control Strategy

Of the 6 control strategies described in section III, MP almost exclusively utilizes two in order to control reactive devices across its system:

- Voltage measurement control– capacitor bank will be switched On/Off based on the measured voltage.
- Manual control – capacitor bank will be switched On/Off by the operator, based on needs.

Voltage measurement control is the primary and preferred method of capacitor bank control on the MP system. This allows the switching to occur automatically based on actual real-time conditions. It also allows for corrective action to occur automatically without human intervention which can be very important when conditions change rapidly such as following the loss of a transmission line or large industrial customer load. Typically, voltage settings from planning studies are applied with generic settings such as switching in a capacitor once voltage drops below 1.0 pu for 15 seconds, and switching back out once voltage exceeds 1.05 pu for greater than 15 seconds. These voltage thresholds, as stated above, match the limits of MP's planning criteria. For system planning purposes, this represents the largest window of operation for the capacitor in order to limit unnecessary switching. While it is sometimes common for banks to be manually controlled in planning models, these modeled scenarios are meant to represent stressed conditions which will result in predicable statuses for reactive devices. However, the dynamic nature of the actual system requires dynamic resources that respond to changing conditions.

Manual control at MP is reserved primarily for contingency conditions such as planned transmission line or transformer outages and regional operating conditions which have caused or might cause bank stability issues such as cycling.

E.Operational Verification

Even with detailed and robust study processes it is important to periodically review operational metrics associated with capacitor banks. MP VAR resources that switch excessively are flagged and reported by System Operators who are watching for these types of issues. The System Operators are instructed to place the toggling bank in manual mode while adjusting voltage based on need, and continue to closely monitor the local area for changes that occur. The root cause of excessive toggling can normally be determined based on archived telemetered data. If setting changes are required, they are communicated back to planning for inclusion in future planning assessments. Other less noticeable switching is reviewed on a periodic basis to ensure that settings continue to be appropriate. Due to the variable regional power transfers on the MP high voltage system, it is not unusual for 230KV capacitor banks to switch on during morning load ramp periods and then switch back off in the evening when load drops off. However, if those same banks switch multiple times during the day the cumulative operations will quickly add up over the course of many years, causing excessive stress on switching devices and possibly disturbing customer load. For this reason, periodic reviews are required to assure settings are harmonious with the state of the system they are connected to.

Another important aspect of capacitor bank operation is customer impacts. With multiple large industrial customers spread across the transmission system it is very important to ensure that switching of reactive resources does not have negative impacts during any potential system configurations. Examples of negative impacts on customers include variable frequency drive fed motor tripping due to fast voltage transients and voltage sags following clearing of system short circuits.

VIII. Conclusions

Modern capacitor bank controllers offer many options and functionality to control capacitor banks for voltage/VAR regulation in both transmission and distribution systems. They allow manual (local or remote) or automatic control based on the available measurements. They also provide interlocking means to ensure safe operation of the capacitor banks. They have the capability to control multiple capacitor banks and execute programmed operations sequence automatically or manually.

When it comes to coordination with other devices controlling voltage and VAR, such as other capacitor banks and load tap changers, it becomes quite complicated with automatic volts/VAR control mode to ensure all controllers are working in unison and no switching races exist between them. For these situations, its preferred to have a combination of the timed-based approach per known VAR deficit to take care of large chunks of the VAR demand and capacitor bank automatic control for smaller chunks of the VAR demand. Having different capacitor bank sizes helps to control voltage and VARs more effectively.

Alternatively, Distribution Management Systems can provide a centralized Volt/VAR strategy by taking measurements from multiple points of the system and controlling capacitor banks and LTCs remotely. This can achieve optimum system voltage profile by regulating voltage and reactive power flow throughout the system, thus improving power quality and minimizing power losses.

IX. Literature:

1. IEEE Std. C37.99-2012 -Guide for the Protection of Shunt Capacitor Banks.
2. IEEE Std. 1036-2010 - IEEE Guide for the Application of Shunt Power Capacitors.
3. GE publication GEK-130995, C70 Capacitor Bank Protection and Control System - Instruction Manual, 2017

X. Biographies

Scott Hoberg is a Supervising Engineer at Minnesota Power in Duluth, Minnesota. He has worked for MP in the System Performance group for 10 years. Prior to joining MP, Scott worked for MISO as a Real Time Operations Engineer. He received his Bachelor of Science in Electrical Engineering from South Dakota State in 2000.

Ilia Voloh received his Electrical Engineering degree from Ivanovo State Power University, Russia. He is currently a senior application engineer with GE Grid Solutions in Markham Ontario, and he has been heavily involved in the development of UR-series and 8-series of relays. His areas of interest are current differential relaying, distance relaying, advanced algorithm and advanced communications for protective relaying. Ilia authored and co-authored more than 40 papers presented at major North America Protective Relaying conferences. He is a recipient of the best paper award at Georgia Institute and Technology Protective Relaying Conference in 2012. Ilia is a senior member of the IEEE, member of the IEEE PSRC main committee, a member of the IEC TC 95 committee and a member of the CIGRE B5.65 working group.

Tom Ernst is a semi-retired P&C Technical Application Engineer for the GE Grid Solutions North American Commercial team. He has been with GE since 2011 supporting the Grid Automation Protection and Control Portfolio. Prior to joining GE, Tom has been with Minnesota Power as a Supervising Engineer, Delta Engineering International as a Manager of Electrical Engineering, HDR Engineering as a Manager of Electrical Engineering and Northern States Power as a Supervising Engineer. He received his Bachelor of Science in Electrical Engineering from the University of Minnesota in 1978 and his Master of Science in Power Systems from Michigan Technological University in 2008. He is a long-time member of the IEEE Power and Energy Society.